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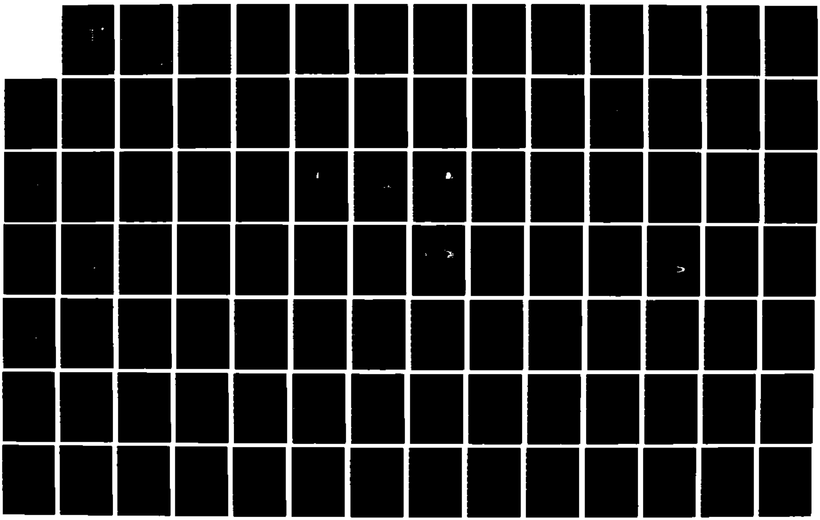

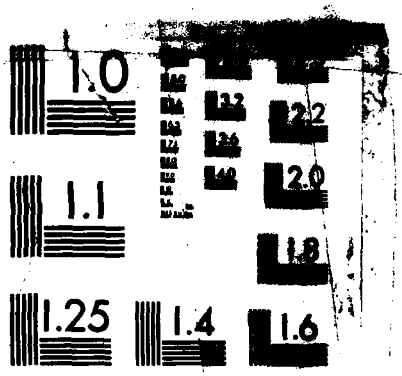
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AN ANALYSIS OF THE POTENTIAL FOR ENHANCED OIL RECOVERY IN THE SHANNON FORMATION AT NAVAL PETROLEUM RESERVE NO. 3

BY

HARLAN HUGH CHAPPELLE, B.CHE.

REPORT

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

MASTER OF SCIENCE IN ENGINEERING

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Most of all, I thank my wonderful wife, Ginger, and my children, Bryan and Sherry, for their loving support and understanding.

December 26, 1984

ABSTRACT

Three EOR processes were evaluated for potential application in the Shannon reservoir at Naval Petroleum Reserve No. 3, in the Teapot Dome Oilfield near Casper, Wyoming. This reservoir is estimated to have originally held 180 million barrels of oil, of which only 8 million barrels are recoverable by primary means. Simplified computer models were used to predict the performance of in-situ combustion, polymer flooding, and steam flooding. Economic analyses were done on the results of these predictions and sensitivity studies were performed for various physical and economic parameters.

This report provides a foundation of information, offers a template for economic decisions, and makes preliminary recommendations based on performance predictions. Before field-wide application of any project is undertaken, a better characterization of the reservoir must be accomplished, and pilot projects evaluated. However, this analysis suggests that the most favorable application in the Shannon Sandstone is polymer flooding operated on 2.5-acre spacing. This technique is predicted to give a net present value of $5.43 million per 10-acre unit with a present value ratio of 9.4 for its four year economic life.

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Table 2.2 Results of Preliminary EOR Screen (Core Labs, Dec. 1978).

Ranking	Process
1	Polymer Flooding
2	Steam Flooding
3	Micellar/Polymer Flooding
4	In-Situ Combustion

Subsequent to the screening process, a reservoir model based on an areal grid of 352 blocks was used to predict the performance of the candidate technologies [Core Labs (Jul. 1979)]. Core Labs found that water flooding, polymer flooding, in-situ combustion, and micellar flooding held the most promise for the Shannon formation, while steamflooding was ruled out as a candidate. Although core floods had shown average residual oil to steam (S_{ors}) of 12%, it was predicted that fuel oil requirements for steam generation would be greater than actual oil production. Estimates were that first year production would be approximately 18 Mbbl of oil, requiring the use of a 10 MMBtu/hr steam generator. Core Labs stated that fuel oil use would be 70 BOPD or over 25 Mbbl/yr under these conditions. Reproducing the production prediction was not possible since anticipated injection rates were not reported. However, in applying a heuristic given by Miller (1984), it was found that the fuel oil requirement would be about 50 BOPD, or just over 18 Mbbl/yr were the generator operating at peak capacity at all times. This

evaluation. Results are at best inconclusive, and portions of the work done to date are poorly documented and of questionable quality.

In 1977, DOE employed SSC to evaluate the Shannon for potential production improvements. With the use of a three-dimensional model, oil-in-place calculations were done, fluid and reservoir properties evaluated, and recommendations were made. SSC reported that based on data gathered from well logs and U. S. Geologic Survey maps, the Shannon formation contained approximately 180 MMbbl of oil, and that primary production would be limited to about 5% of the total. They further recommended 10-acre well spacing as well as additional studies for possible EOR applications. It should be noted that the material balance approach apparently taken by SSC to quantify the amount of oil in place may not be valid for a reservoir as heterogeneous as the Shannon. However, subsequent calculations performed by Core Labs were within a fraction of a per cent of the original SSC findings.

Following the analysis performed by SSC, DOE awarded a contract to Core Labs in 1978 to "determine the most suitable engineering and economic enhanced oil recovery method which would merit a pilot test and ultimately lead to a full scale field application" [Core Labs (Sept. 1978)]. The first step in the evaluation process for Core Labs was to conduct a preliminary screen of potential EOR methods. Based on criteria published by Geffen (1973), Lewin and Associates (1976), and the Gulf Universities Research Consortium (1973), Core Labs ranked four EOR processes as shown in Table 2.2.

Total primary recovery from the Shannon is projected to be only 8 MMbbl [DOE (Aug. 1983)]. No previous attempts at field-wide EOR projects have been attempted. However, a waterflood performed in the adjacent East Teapot field portion of the same reservoir resulted in breakthrough occurring in offset wells in a matter or weeks. No further attempts have been made to use a waterflood in the formation.

The vast amount of oil that will remain unrecovered after primary production motivated DOE to begin evaluating EOR potential for the Shannon formation in 1977. Based on the recommendatons of consultants, pilot projects were initiated in 1979-1980for the evaluation of polymer-improved waterflooding and in-situ combustion. The processes of steamflooding and horizontal drilling are also currently under consideration for pilot testing. To date, considerable resources have been expended toward the goal of economically improving oil recovery from the Shannon. Since the initiation of pilot projects in 1979, EOR evaluation efforts have produced a net loss of approximately $11million [DOE (Aug. 1984)].

Due to the high costs that usually follow the decision to undertake an EOR process, a significant amount of effort is usually expended to improve the accuracy of performance predictions. This has been the case thusfar for the Shannon formation, as a number of studies, as well as studies of the studies, have been conducted. Analysis of the Shannon for possible EOR application began in 1977 and has progressed through various stages of

as listed by Core Labs range from 48% to 59% in Pool No. 2. However, they also list extremely high irreducible water saturations of 46 to 58%, even though the sandstone is believed to be water-wet. For this report, an irreducible water saturation of 40% is assumed to be more realistic.

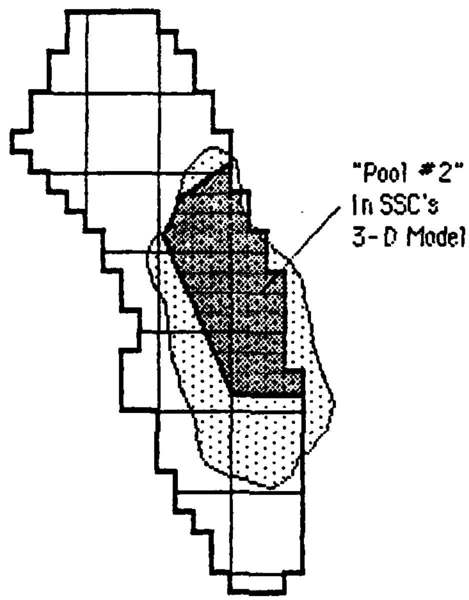

Fig. 2.5. A map showing the portion of the Shannon formation considered in this report. SSC modelled the reservoir as eight "pools". Pool No. 2 contains 110 MMbbl of oil out of total Shannon oil of 180 MMbbl.

2.3 Previous Predictions

The Shannon formation is a two-bench shaley sandstone reservoir which is essentially fully developed on ten acre spacing with approximately 400 wells. It is estimated to have originally contained 180 million barrels (MMbbl) of oil, of which approximately 5.5 MMbbl have been recovered to date.

The Shannon formation is a shallow, low-pressure reservoir 300-700 feet in depth. Considering the two benches together, the Shannon formation in Pool No. 2 has a gross thickness of approximately 97 feet, with net pay thickness averaging 76 feet. It has an average porosity of about 20%, and its permeability ranges from 0.1 to 1000 md. Both Curry (1977) and the DOE (1983) report an average permeability of 200 md. However, Core Labs has reported an average air permeability of 63.3 md [Core Labs (Oct. 1978)] and a Dykstra-Parsons permeability variation [as described by Caudle (1968)] of 0.90. Although not apparent from reports by Core Labs, it is assumed that the values were for the entire field. The value of 200 md was more representative of Pool no. 2, as was a more conservative Dykstra-Parsons coefficient of 0.8. Where appropriate in this report, sensitivity analysis is performed on permeability variation. According to a report by Lawrence-Allison and Associates, West (LAW) (1984), DOE's prime contractor at NPR-3, there is no discontinuity in the Shannon formation within NPR-3 boundaries. They further state that there is probably no intercommunication between the two benches.

The Shannon formation has an oil saturation which ranges between 40 and 51%, averaging 45%. Average gas saturation is 3%, and the solution gas-oil ratio is approximately 32 SCF/STB. The oil is relatively light with API gravities measured from 29°API to 34°API. Oil viscosity is between 7 and 20 cp, averaging 10 cp. Formation water is relatively fresh with an average of 13000 ppm TDS and hardness of 300 ppm Ca/Mg. Water saturations

and other parameters. This does not mean that these parameters exist as singular values but rather these properties may be described in terms of field-wide trends or possibly as average properties belonging to a particular "zone" of the reservoir. The reservoir study of the Shannon sandstone at the Hartzog Draw field, just north of NPR-3, is an example of such a description. In this study, Hearns, et al. (1984) mapped "reservoir flow units" for the Shannon formation in order to "...more precisely describe variations in rock properties that control fluid flow." Such a comprehensive study has not been accomplished to date at NPR-3. However, much data is available with which to describe at least average properties of the Shannon reservoir.

Table 2.1 summarizes the physical properties of the Shannon formation, listing average values taken primarily from recent work done by Scientific Software Corporation (SSC) (1977), and Core Laboratories, Inc. (Core Labs) (1978, 1979) for the DOE at NPR-3. In the course of their work, SSC characterized the Shannon using a three-dimensional model made up of eight "pools". Core Labs continued to use this model as a tool as they collected numerous data on the Shannon formation. While many NPR-3 documents refer to average properties of the Shannon considering all eight pools, this report uses average properties for the area that SSC designated as "Pool 2", which is shown in Fig. 2.5. This area was chosen as being representative of the portions of the formation which would potentially be exploited for EOR, since it has an estimated 110 MMbbl (out of the estimated 180 MMbbl total) of oil in place, and has generally more favorable properties than do the other areas.

area was subjected to tectonic stresses which formed the anticlinal structure which, in part, exists today at NPR-3. This anticline is the same structure upon which the mammoth Salt Creek field is situated. Tensional stresses placed on the structure as beds were stretched along the anticlinal axis induced faulting and fracturing, adding to the complexity of the reservoir.

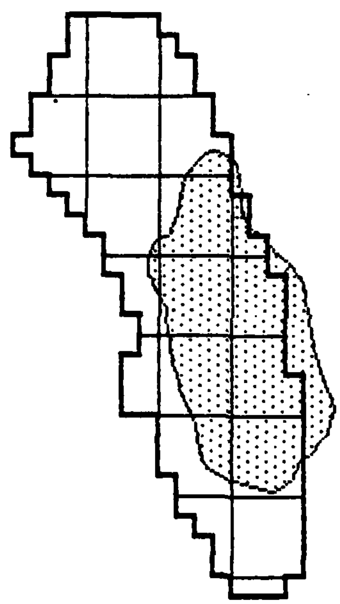

Fig. 2.4. A map of NPR-3 showing the general areal extent of the Shannon formation. Note that the eastern portion of the reservoir extends into the adjacent East Teapot field.

2.2.2 Physical Properties

While awareness of deposition and diagenesis can give a qualitative understanding of reservoir behavior, it is necessary to accurately define its character in terms of permeability, porosity, bed thickness, fluid saturations,

environment. Consequently, the Shannon is typically composed of two similar sand sequences, or benches, separated by a silty shale. Spearing describes these two facies as an upper sequence which is a cross-bedded sandstone, and a lower sequence which is a thin-bedded sandstone. With progradation, the sand bars were encased in organic-rich marine shale which acted as both a source rock and seal, forming a stratigraphic trap.

Neither of the two sand benches is homogeneous or isotropic. Spearing describes the lower thin-bedded sandstone facies as containing individual sand beds which are 2-50 cm thick, rippled and burrowed, and separated from each other by thin suspension clay layers. These layers may be a few millimeters or several centimeters thick. In places, this facies is broken by cross-stratified sand beds containing clay chips and rounded clay clasts. Spearing states that the upper cross-bedded facies is capped by burrowed, glauconitic cross-stratified beds containing clay clasts up to 8 cm in diameter. The individual sand beds are 5-65 cm thick and commonly separated by clay streaks. Three cross-bed types, a low-angle cross-bed, a tabular cross-bed, and a trough cross-bed, respectively, occur in vertical succession. Sandy patches are also present, which are separated from other sands by muddy areas.

As previously discussed and shown in Fig. 2.2, the Shannon formation is encased in the Steele Shale, which was its source rock and seal. Figure 2.4 illustrates the areal extent of the Shannon formation at NPR-3. After deposition and the progradation which covered the Cretaceous seaway, the

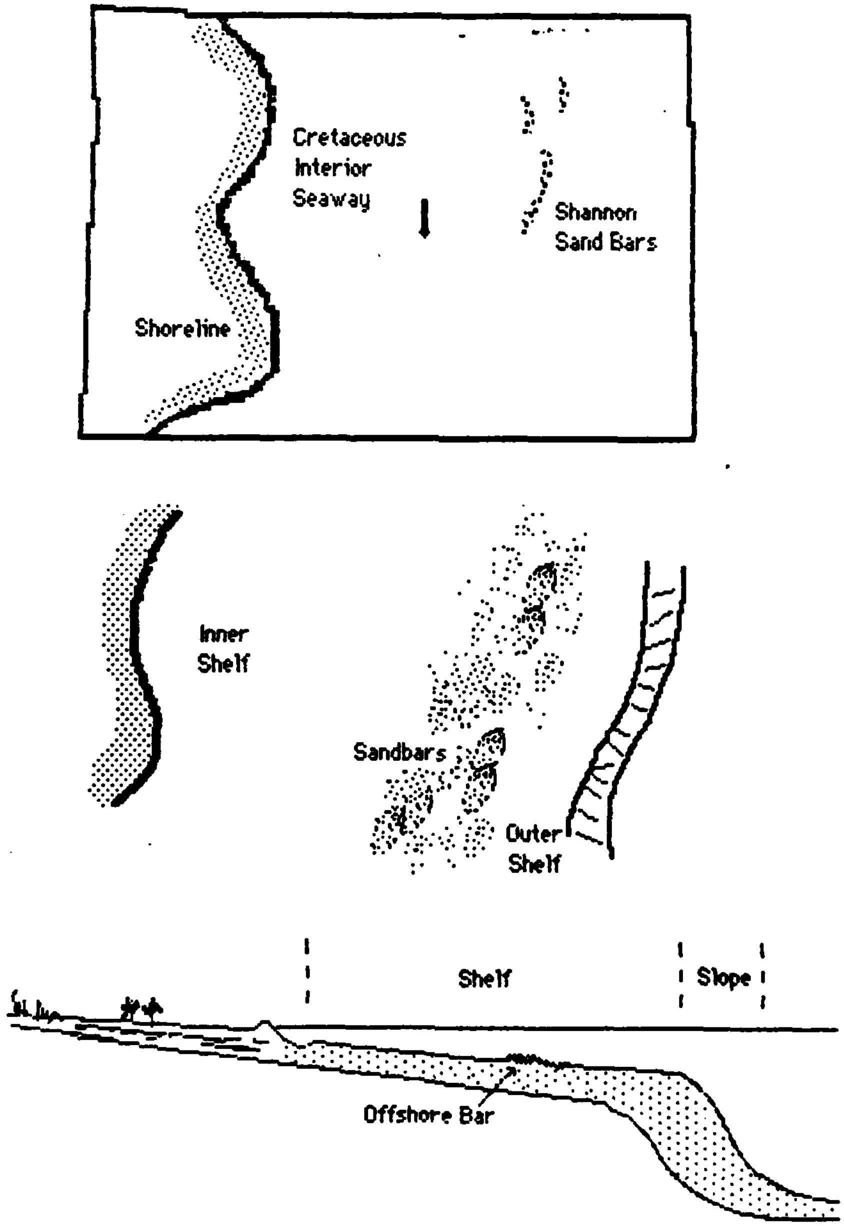

Fig. 2.3. A reconstruction of the environment present when the Shannon formation was deposited in late Cretaceous time. Sand ridges migrated in a southerly direction and built upon one another. The progradational marine shales which made up shelf deposits were both source rock and seal [after Spearing (1976)].

2.2 Reservoir Description

An understanding of deposition, diagenesis, and the resulting physical properties of a reservoir and its fluids is necessary when oil production is being evaluated or future performance is being predicted. Most reservoir engineering computations are based to some extent on assumptions and/or approximations. How valid these are often can only be ascertained with an appreciation for the character of a reservoir, such as its bedding characteristics, fault planes, or areal variations in fluid properties. Therefore, it was felt to be useful to characterize the Shannon from the standpoint of geology and physical properties.

2.2.1 Geology

The Shannon formation was deposited in late Cretaceous time as an offshore bar on the western flank of the Cretaceous interior seaway. Figure 2.3 is a reconstruction of the Cretaceous environment, showing that the sand bodies were "situated at the top of a progradational shelf sequence composed mainly of offshore mud deposits" [Spearing (1976)]. Parker (1960) states that Shannon sands were deposited 50-200 miles from shore. Boyles and Scott (1982) suggest that water depths were 200-400 feet. Sand ridges migrated southward as discrete bodies in response to storm waves and oceanic or tidal currents, causing layer upon layer of sand sheets to build up. Spearing proposes that this was analogous to present-day "sand ribbons" in the North Sea. During fair weather, shale laminae were formed between sand sheets as suspension clays were deposited. As sand bodies built vertically, bed forms changed from ripples to sand waves and cross beds, due to the higher-energy

Classified as a stripper field, NPR-3 generates revenues of over $35 million per year, while operating on an annual budget of nearly $22 million, resulting in an approximate annual net cash flow to the U. S. Treasury of $13 million. Presently, NPR-3 produces approximately 1.1MMbbl of oil annually at a rate of over 3000 barrels of oil per day (BOPD) from its 10 producing formations. Oil and natural gas produced from NPR-3 is sold on the open market. No state, local, or federal taxes are levied on the production. Figure 2.2 is a partial depiction of the geologic column at NPR-3 which shows the relative positions of the producing formations. The richest and most productive zones are the Shannon and the Second Wall Creek formations, both of which yield approximately 1000 BOPD.

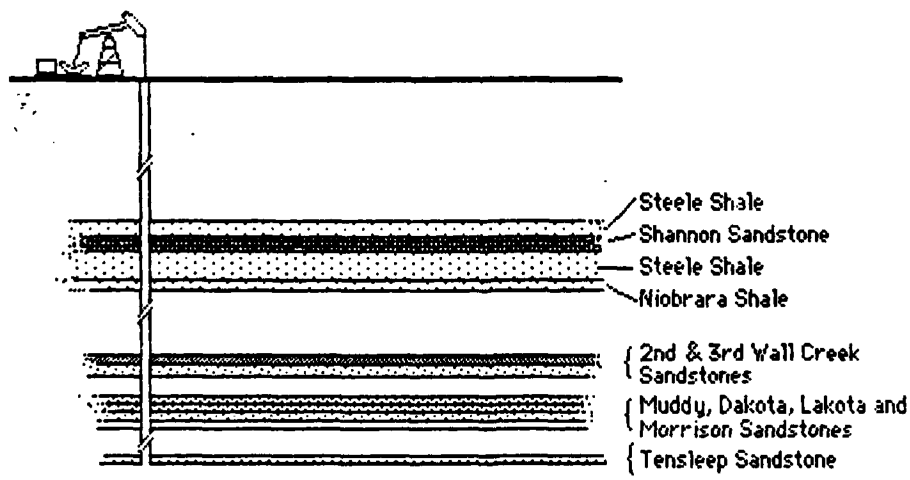

Fig. 2.2. A simple cross-sectional view of the producing formations at NPR-3. The shallowest wells are completed in the Shannon at an average depth of 550 feet, while the average depth of a Tensleep well is 5500 feet.

Table 2.1 Physical Properties of the Shannon Formation

Reservoir Properties	
Producing Formation	Shannon Sandstone
Average Depth, ft	550
OOIP, MMbbl	180
Average Temperature, °F	65
Average Pressure, psia	70
Average Net Pay, ft	76
Average Gross Pay, ft	97
Rock Properties	
Porosity, fraction	0.198
Permeability, md *	200
Permeability Variation	0.8-0.9
Fluid Properties	
Initial Water Saturation, fraction	0.52
Irreducible Water Saturation, fraction*	0.40
Initial Oil Saturation, fraction	0.45
Irreducible Oil Saturation, fraction	0.25
Initial Gas Saturation, fraction	0.03
API Gravity, °API	32
Oil Viscosity, cp @ 65°F	10
Formation Water Salinity, ppm TDS	13000
Formation Water Hardness, ppm Ca/Mg	300

* See Text

2. BACKGROUND

2.1 Field History

NPR-3, located as shown in Fig. 2.1, was established in 1915 in the Teapot Dome oil field by an executive order from President Wilson, in order to provide the Navy a source of fuel as ships were converted from coal to petroleum power. After transfer of administration of the NPR's to the Department of Interior, and the subsequent Teapot Dome Scandal, NPR-3 was shut in from 1927 to 1958. At that time, it was re-activated to protect against drainage by adjacent operators. Full-scale oilfield operations began when in response to the Arab oil embargo, Congress passed the Production Act of 1976, which granted the Department of Energy (DOE) authority to produce oil from the NPR's at the "maximum efficent rate".

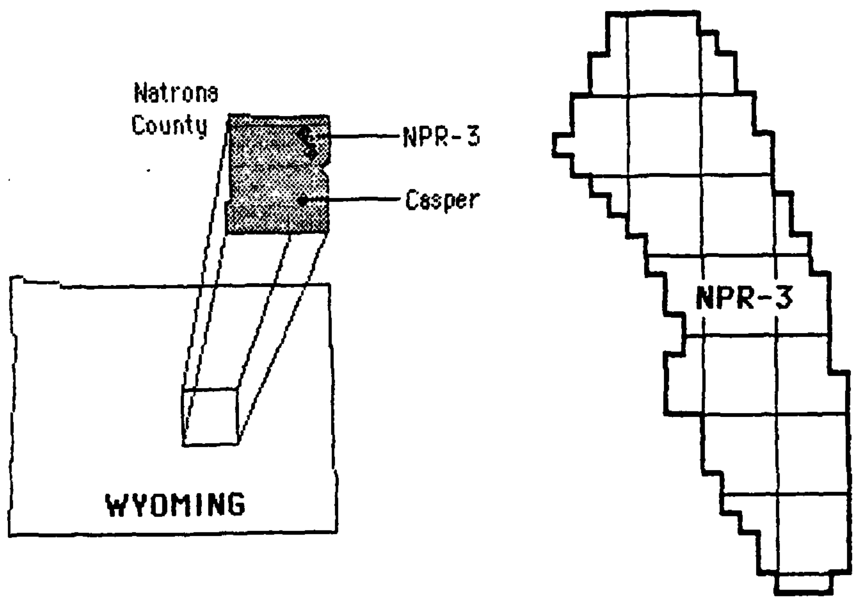

Fig. 2.1. Location of Naval Petroleum Reserve No. 3.

1. INTRODUCTION

The purpose of this report is to evaluate and compare the potential for each of three enhanced oil recovery (EOR) processes in the Shannon formation at Naval Petroleum Reserve No. 3 (NPR-3), located on the southwestern margin of the Powder River basin in Wyoming. EOR is receiving significant emphasis in many reservoirs as conventional methods are becoming unfruitful. Such is the case at NPR-3 where the Shannon formation is estimated to have originally contained 180 million barrels of oil (MMbbl), of which 5.5 MMbbl have been produced to date and only a total of 8 MMbbl are predicted to be recoverable by conventional means. The Department of Energy (DOE) operates NPR-3 and is currently evaluating various EOR applications as well as conducting two pilot tests.

Most applications are high in cost and technically complex, requiring the analysis of many physical and economic factors before a decision is made as to whether or not to proceed with a particular technology. In order to adequately determine the effect of these many factors, it is often necessary to predict the performance of a process under varying physical and economic conditions. To accomplish this for the Shannon formation, computer models developed at The University of Texas at Austin were used to predict the performance of in-situ combustion, polymer flooding and steam flooding. Economic analyses were performed through the use of a microcomputer spreadsheet model.

would still be unfavorable assuming the prediction of 18 Mbbl of oil produced in the first year was valid, but not nearly as much as reported by Core Labs.

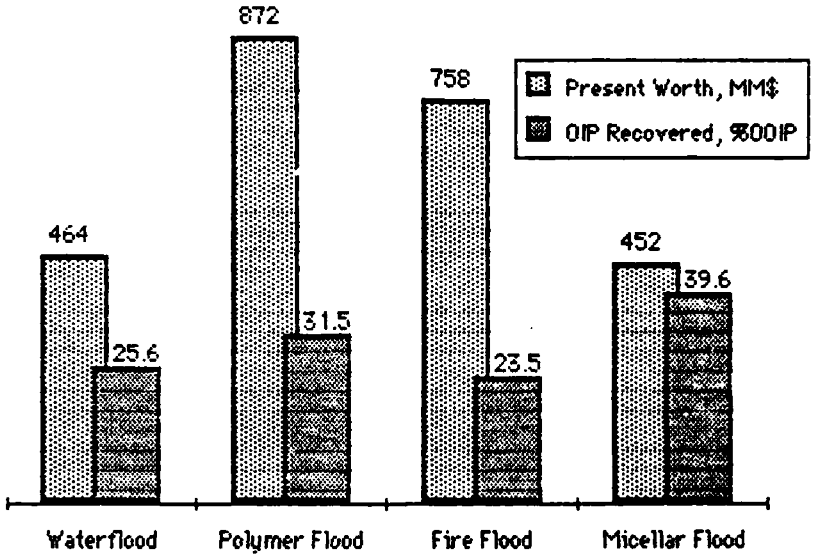

Fig. 2.6. Results of the preliminary performance predictions made by Core Labs for EOR projects in the Shannon formation. Note that Steamflooding was not included [Core Labs (July 1979)].

Figure 2.6 gives predicted recoveries as per cent of oil-in-place and predicted "present worth", using a 10% discount rate and 1979 dollars. These results are based on developing 320 acres with 5-acre 5-spot patterns and project lives of approximately 30 years. As can be seen from Fig. 2.6, the most attractive processes were in-situ combustion and polymer flooding. However, the predicted results for all of the four processes appear to be quite good. An unfortunate aspect of the work which was done is that there are no apparent references to predictive methods employed. Additionally, the

economic analysis could not be duplicated through the application of methods as given by Peters and Timmerhaus (1980) or van Rensburg (1984).

2.4 Pilot Projects

The predictions shown in Fig. 2.6 resulted in the initiation of two pilot projects, one to test in-situ combustion, the other to evaluate polymer flooding. Before field-wide application of a process, common practice is to initiate a pilot project in which a small, but hopefully representative portion of the reservoir is used for testing. Primary concern in a pilot is not economic success, but technical viability. In other words, "will it work?". It should also be the source of many "lessons learned", such as proper operating procedures, material and equipment selection, and optimum performance parameters. After a sufficiently long pilot test, all factors may be analyzed once again before a decision for field-wide expansion is made.

For the Shannon formation, pilot project planning and construction began in 1980. In late 1982 both the in-situ combustion and polymer flooding projects commenced. It is not the purpose of this report to evaluate pilot project performance. But, it is noteworthy that the pilot projects at NPR-3 have been plagued from the beginning with "...many changes in technical direction and thrust in the implementation of EOR on the Shannon as various technical approaches (have proved) unsatisfactory" [DOE (Aug. 1984)]. Among the things learned from the operation of the pilot projects have been operating procedures, materials selection, and attainable injectivities. One significant item found while operating the in-situ combustion pilot was that

combustion could not be sustained with air injection alone. The decision was made to pre-heat the reservoir with steam injection. During the period of steam injection, a steam drive was developed and significant increases in production were measured. This renewed interest in steam flooding as a possible application and has lead to consideration of pilot testing in 1985 or 1986.

3. PREDICTIVE MODELS

As in the case of the Shannon formation, large amounts of money, time, and effort may be expended trying to determine the viability of EOR in a particular reservoir. Extensive studies may be undertaken, often involving the use of expensive, time-consuming three-dimensional reservoir computer simulations in the hope of predicting performance. These models depict reservoirs as a grid of "cells", each typically on the order of 100 ft on each side. For such models to be worthwhile, large amounts of data are required. Analysis is often limited to a small number of situations due to the time and expense involved. When such data is unavailable or unreliable, analysis may more properly revert to simplified predictive methods.

Examples of easily used hand calculation methods are those given by Gates and Ramey (1980), Caudle (1968), and Vogel (1984) for in-situ combustion, improved waterflooding, and steamflooding, respectively. Miller (1984) argues that hand calculation methods may often be just as reliable as the large computer simulations, particularly when data are scarce.

Miller further points out that the most significant value of simplified predictive methods is in sensitivity analysis. Through sensitivity analysis, "what if" questions may be asked regarding any parameter in order to see the effect that it has on total process performance. Critical variables may be identified for further study, such as the effect of reservoir permeability heterogeneity or solution gas/oil ratio.

However, even "simple" hand solution methods are time-consuming and cumbersome if more than a few cases are to be examined. Also, some variables may not be known and may need to be estimated from published correlations. Therefore, to better accomplish sensitivity analysis in performance prediction, computer models which combine simplified predictive methods and correlations for various properties are often used. Based on energy and mass balances, these computer models provide a "middle ground" between hand calculations and reservoir simulators. Many variables may be quickly and easily tested for their effect on a particular process in a small fraction of the time required for either hand calculations or reservoir simulators. Following is a discussion of the three computer models developed at The University of Texas at Austin which were used in this study.

3.1 In-Situ Combustion Predictive Model

Genrich (1984) proposed a simplified linear frontal advance model to "predict fluid production of forward, non-superwet in-situ combustion processes." By combining energy and mass balances, he modelled the process as four homogeneous zones: a burned zone, a combustion zone, a steam zone, and a cold zone. For each zone, compositions, saturations, and fractional flows of three phases are calculated. Overlay calculations were included for the steam zone and combustion zone to account for gravity override effects. Figure 3.1 is a schematic illustration of the model.

Genrich's model successfully history-matched one actual project, the Suplacu de Barcau field, and a combustion tube experiment. He indicates that the model should give "order of magnitude estimates" of fluid production

from an in-situ combustion project. He also recognized shortcomings of his model with regard to pressure calculations and default parameters, and made recommendations for further modifications. Additionally, no allowance was made for permeability variation.

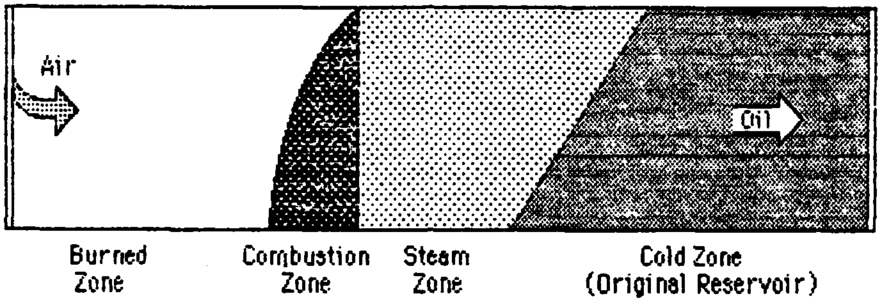

Fig. 3.1. An illustration of the four homogeneous zones characterized in Genrich's (1984) in-situ combustion model.

As far as can be ascertained, this report is the first published application of Genrich's model beyond his original studies. Therefore, results should be viewed in that light. Appendix 10.1.1 contains output representative of the results obtained in this study, along with a sample listing of required and optional input.

3.2 Polymer Flooding Model

Jones (1983) developed a predictive model for polymer flooding which accounts for vertical heterogeneity and crossflow of fluids. The basic premise of Jones' calculations is the conductivity ratio method for fluid displacement given by Caudle (1968). Areal sweep correction factors are applied to linear calculations in order to describe pattern flood performance. Figure 3.2 gives the general concept employed by the model for the case of

non-communicating layers. Jones' model allows the user to enter very limited or very extensive information regarding formation properties. The model also considers a large number of flow properties which as Jones states, are "...usually...accounted for only in reservoir simulators".

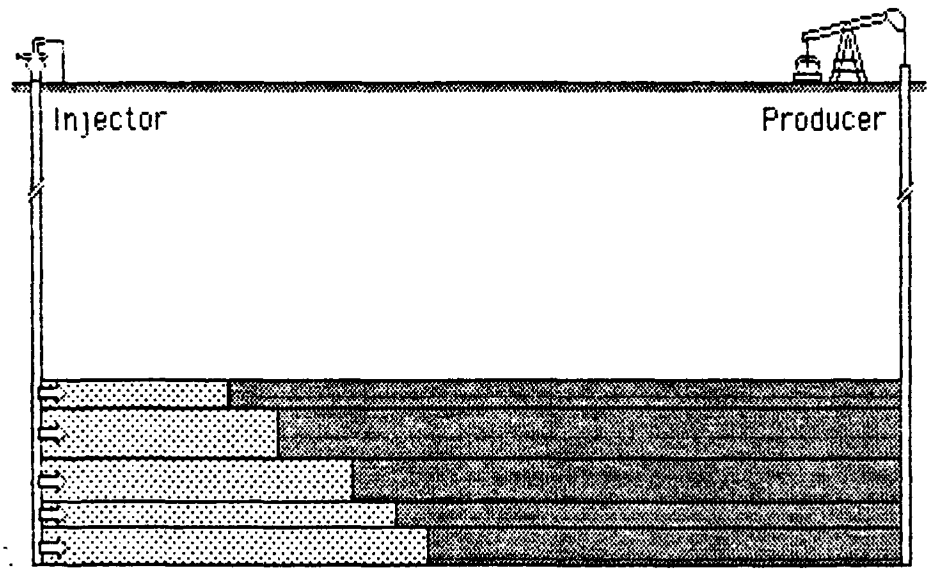

Fig. 3.2. A diagram illustrating the approach taken by Jones in simulating fluid flow in multiple layers. This simple case is for five non-communicating layers of varying thickness.

Jones successfully history-matched the performance of two polymer floods and showed that results agreed closely with those calculated by large numerical simulator models. The model is limited primarily by the quality of input data used, i.e., whether or not the properties of multiple layers are known. Additionally, it assumes lateral continuity of layers. As was done with the in-situ combustion model, a sample computer output is given in Appendix 10.1.2.

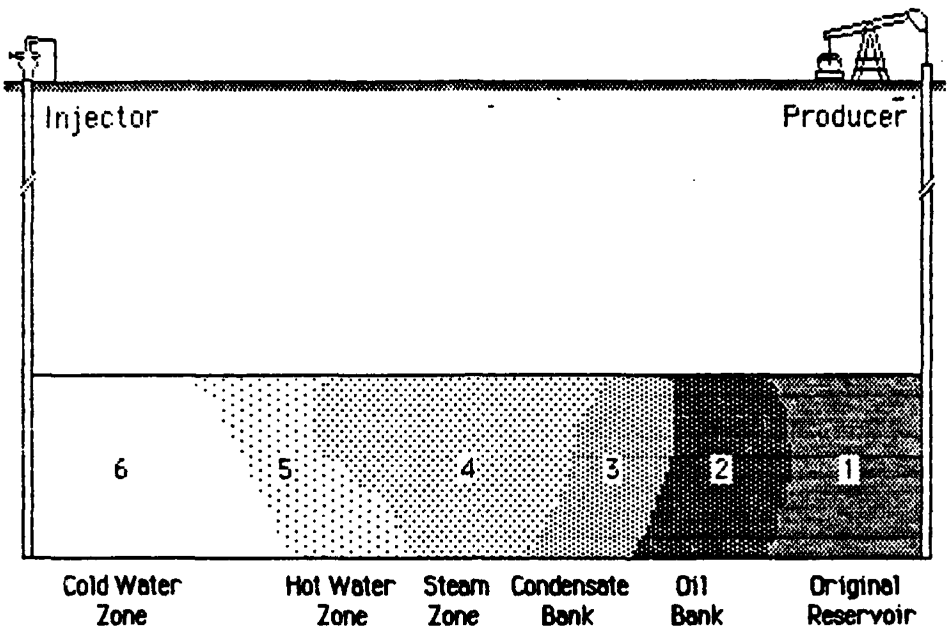

Fig. 3.3. A diagram depicting the various zones across which energy and mass balance equations are applied in Arima's (1984) steam flooding model. Note that the oil bank may not be formed, and the condensate bank also contains hot oil and water.

3.3 Steamflooding Model

The steamflood predictive model proposed by Arima (1984) is a modification of that given by Aydelotte and Pope (1983). It applies energy and mass balances to a linear system of six homogeneous zones as shown in Fig. 3.3, correcting for gravity override and radial flow by the use of a steam overlay and an areal sweep efficiency, respectively. The steam overlay is found by applying corrections for vertical sweep efficiency and fractional flow, and areal sweep efficiency is taken from published correlations.

Arima provided an extensive suite of sensitivity analyses which were in good agreement with actual field performance and performed a number of

successful history matches for very different cases. One drawback to the model, however, is that it does not account for permeability variation, and therefore may predict too long a steam breakthrough time. Additionally, the model shows oscillating behavior late in project life.

Arima's model was being written and revised at the same time that the predictions for this study were made. The final version of the model was used for all predictions. When evaluating the results of this study it should be noted that this is the first test of the model beyond Arima's work. Appendix 10.1.3contains a data template and sample output obtained from this predictive model.

4. PROBLEM STATEMENT

It is estimated that of the 180 MMbbl of oil originally contained in the Shannon formation of NPR-3, only 8 MMbbl are recoverable by conventional means. Therefore it is necessary to determine what form of improved oil recovery will be most advantageous in order to increase the ultimate production of oil from this reservoir, as well as cash flow to the U.S. Treasury.

EOR processes have previously been evaluated for the Shannon formation, and polymer flooding and in-situ combustion pilot projects have been in operation for over two years. Another technique, steamflooding, is also being considered. However, results of the pilot tests are inconclusive and many questions about the application of EOR in the reservoir still remain. Thus, it was felt that it would be valuable to predict the performance of these three processes considering the physical properties of the formation and its fluids. Since certain properties vary within the reservoir, or are not well known, not only would economic sensitivity analysis be necessary, but sensitivity analysis for key physical parameters as well. This accomplished, performance prediction will provide only an estimate of production. However, a template for decision-making would be established, and tools with which to judge the relative effects of the physical phenomena involved in the processes in question would be available.

Although only three methods of EOR are under consideration, there is the possibility that some other process may be suited for the Shannon formation. Therefore to make this analysis as comprehensive as possible, a preliminary screening of EOR processes in general is appropriate. This would serve to judge the relative merits of various EOR processes in the context of success of similar projects in industry. It could also highlight processes which should be considered for the Shannon formation.

5. EOR SCREENING

In the six years since EOR methods were first screened for the Shannon, oil prices have dramatically increased and more EOR technology has been applied and evaluated, in general as well as in the pilot projects at NPR-3. In some cases, screening criteria have become more liberal. It was thus believed to be useful to re-evaluate the Shannon Sandstone for possible EOR methods, based on the physical properties of the reservoir and its fluids. This was done both to confirm the applicability of the evaluations done by this report, and to indicate any other methods which may be applied to the Shannon.

Table 5.1 summarizes screening criteria used in this evaluation, and lists properties of the Shannon for reference. Unless otherwise noted, the parameters are based on the screening guides published by Taber and Martin (1983). Additions and changes are discussed herein. Processes were judged to have either favorable, marginal, or unfavorable potential. The results of the screen are given in Table 5.2 at the end of this chapter.

Before discussing EOR screening of the Shannon Sandstone, it is important to recognize the limitations of such a "binary screen", i.e. one in which a reservoir or fluid property is matched against a preferred value for a certain process. These "preferred values" are obtained from laboratory

Table 5.1 Screening Criteria for Potential EOR Projects

	Shannon Sandstone Properties (Avg)	Polymer-Improved Waterflooding	Alkaline Flooding	Surfactant/Polymer Flooding	Miscible Gas Drives, including CO_2	Steamflooding	In-Situ Combustion	Horizontal Drilling
Gravity °API	32	>18	13-35	>28	>26	10-35	10-40	>10
Depth, ft	400-700	<9000	<9000	<8000	>2000	300 -5000	>500	<4000
Viscosity cp	10	<150	<200	<30	<12	NC	NC	<200
Composition	Light intermediates, 89% C7+	NC	Some Organic Acids	Light intermediates desired	Gas: C1 - C7; CO_2: C5-C12	NC	NC	NC
Acid Number mg KOH/g crude	1.25	NC	5.0	NC	NC	NC	NC	NC
Oil Saturation %PV	45	>10% Mobile Oil	$>S_{or}$	>25	>25	>40	>40	$>S_{or}$
Oil Concentration (ϕSo), bbl/acre-ft	.087/ 680	NS	NS	>.052/ >400	NS	>.065/ >500	>.05/ >390	NS
Avg Permeability md	200	>10	>20	>20	NC	>70	>25	NS
Transmissibility md-ft/cp	240	NS	NS	NS	NS	>100	>20	NS
Formation Type	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone, Carbonate	Sandstone	Sandstone	Sandstone
Existence of Fractures	Many, in areas	Minor	Minor	Minor	Minor	NC	Minor	NC
Salinity ppm TDS	13000	NC	NC	<20000	NC	NC	NC	NC
Hardness ppm Ca & Mg	300	NC	NC	<10000	NC	NC	NC	NC
Temperature °F	70	<200	<200	<175	NC	NC	>150 °F preferred	NC

NC - Not a critical parameter
NS - Not specified as a parameter in literature

research and the results of actual field projects. Prats' (1978) statement that "each reservoir must be evaluated on an individual basis as if there were no screening guidelines available" is fundamental. Also, as noted by Jones, et al. (1984), binary screening does not account for ". . . the composite effect of all variables, and offers no indication of economic feasibility." Therefore, the screening process is not definitive but serves to show the investigator the relative potential of EOR processes with respect to formation and fluid properties, and how these properties have affected previous projects or laboratory studies. The process may also highlight one or more parameters which might strongly suggest the success or failure of a certain application. For example, oil with a viscosity of 10,000 cp would obviously require some form of thermal recovery.

Smith (1983) states that ". . .most low oil recoveries are due to adverse mobility ratios, poor location of injection and producing wells, high residual oil saturation in the contacted part of the reservoir due to heterogeneities, and the immiscible nature of an oil-water displacement mechanism." Some combination of these factors is the target of each of the methods which comprise EOR technology. Enhanced recovery methods have been categorized by Taber and Martin (1983) as follows:

- Improved Waterflooding
- Miscible-Type Waterflooding
- Hydrocarbon and Other "Gas" Methods

boreholes into a maniforld and is collected into a sump for pumping to the surface. Figure 5.4 illustrates the general concept involved. This method has been shown to be effective in shallow, fractured, low-energy reservoirs. Welshimer (1982) points out that it may be the only alternative in older fields in which pressure maintenance is not possible due to primitive plug and abandon procedures. Horizontal drilling is also used in conjunction with steamflooding. The following list is taken from Turner (1984), Dobson and Seelye (1982) and Ste. Nationale Elf Acquitaine of France [Oil and Gas Journal (Dec 26, 1983)], as being the major recovery mechanisms at work when horizontal drilling is employed:

- Gravity drainage
- Large increases in the surface area of drainage above that of conventional vertical wells
- Intercepting of circulation paths (fractures), which are often difficult to locate with vertical wells
- When used with steamflooding, boreholes afford uniform steam distribution

Elf also states that horizontal boreholes are "... geologic tools because an appraisal well could provide samples over a several hundred foot horizontal drain hole."

Screening criteria, per se, were not found for horizontal drilling. However, the screening criteria listed in Table 5.1 reflect the fact that a number of gravity drainage projects in light oil reservoirs (those containing

in the Shannon has been found to be 63 md. However, there is a wide variation in permeability throughout the field and there are large areas which meet the 100 md criterion. Smith (1978) indicates that a higher gravity oil, such as exists in the Shannon, may not require such a high permeability, and may even respond to permeabilities as low as 25 md, which is what is used as the permeability screening criterion.

In-situ combustion was judged to be marginal for the Shannon. Although most of the criteria of Table 5.1 are satisfied, reservoir heterogeneity will probably hamper flow uniformity. A uniform, sustained combustion front is necessary. Unlike steamflooding, injected fluid (air) cannot benefit recovery if it flows through high permeabilty zones and/or overrides other formation fluids.

5.5 Mining and Extraction

Mining methods have been employed for petroleum recovery for a number of years in Europe, and more recently, in the United States. Although excavation is a potential method for removal of petroleum, the mining technique finding widest application in the oil industry is horizontal drilling.

5.5.1 Horizontal Drilling

In horizontal drilling, a mine shaft is dug and an underground chamber, or drilling room, is established from which boreholes of up to 200 ft in length are drilled into the target formation. Oil drains from the

properties. Williams and Ramey (1980) point out the disagreement between oil content values suggested by Chu (1977), Poettmann (1964), and Geffen (1973). These three suggest values of 1000, 780, and 390 bbl/ac-ft, respectively, for minimum oil content requirement. The lower value was used since, as Taber and Martin state, higher gravity oils should consume less fuel and air than would be required by heavier oils.

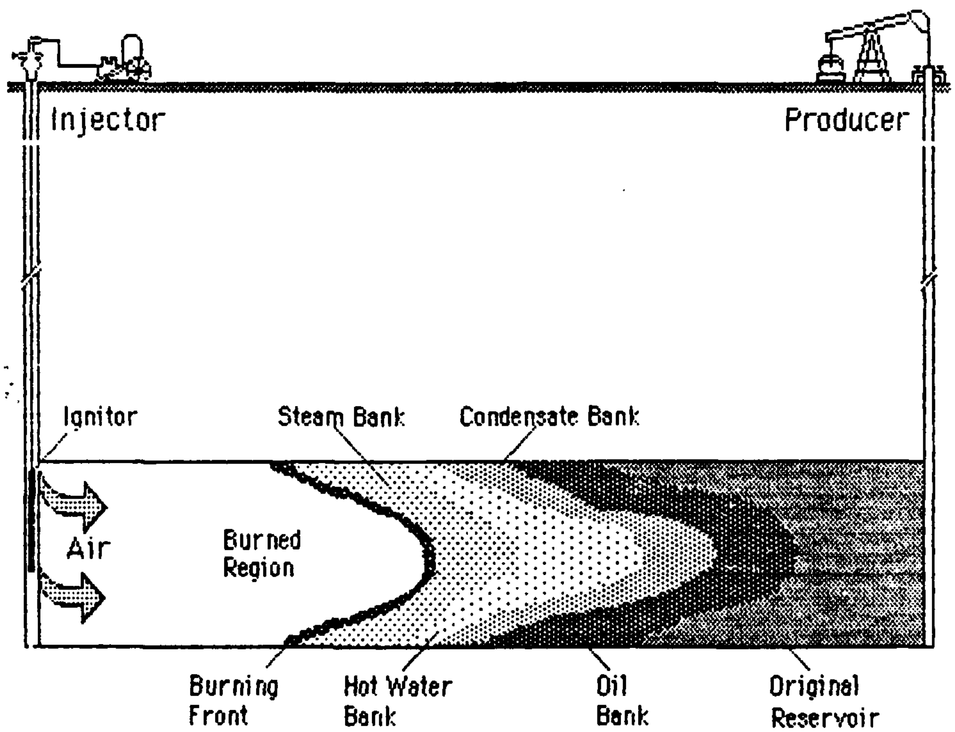

Fig. 5.3. A simplified depiction of the dry in-situ combution process.

A minimum permeability of 100 md is commonly used in evaluating in-situ combustion potential. As mentioned earlier, the average permeability

As listed in Table 5.2, steamflooding was judged to be a good candidate for EOR application in the Shannon. The criteria of Table 5.1 are met, and the process may minimize effects of reservoir heterogeneities. The shallow depth of the formation will allow steam to be injected at a high quality, and the thick pay section should lessen relative heat loss to the overburden and underburden. Also, even though Shannon crude is low in viscosity relative to that in most steam floods, light-oil steamflooding is proving to be successful in other fields.

5.4.2 In-Situ Combustion

In-situ combustion, shown in Fig. 5.3, involves a sustained combustion reaction within the reservoir using part of the reservoir fluid as fuel in order to generate heat. This has normally involved air injection and ignition by downhole heaters, but other methods have been used either to initiate or sustain combustion. These include pre-heating techniques and/or the injection of oxygen-enriched air. Mechanisms which aid in oil recovery by in-situ combustion include:

- Burning "coke" that is produced from the heavy ends of crude oil
- Viscosity reduction by convective and conductive heat transfer
- Residual oil reduction by steam distillation and thermal cracking
- Increased pressure supplied by injected air

Authors differ on some screening criteria, most notably oil content and reservoir temperature, but there seems to be general agreement on other

10°API and 25°API. This is due chiefly to the fact that most steamflooding projects to date have been conducted in reservoirs containing heavier crudes. Steamflooding lighter crudes such as exists in the Shannon reservoir has not been specifically ruled out, however. Blevins, et al. (1984) have reported on successful light-oil steamflooding projects. Information from this study, as well as others such as Hagoort, et al. (1976) and Farouq Ali and Meldau (1979) are considered in the screening criteria of Table 5.1, where 35°API is given as the upper limit.

Permeability is another parameter for which there does not appear to be agreement in the literature with respect to steamflooding. It should be pointed out that most successful steamflooding projects have been conducted in high-permeability reservoirs, with permeabilities typically much greater than 1000 md [Farouq Ali and Meldau (1979)]. A report by the Gulf Universities Research Consortium (1973) states that steamflooding requires a permeability greater than 100 md. Taber and Martin list a requirement of 200 md or greater. Permeability is described as not being critical to steamflooding performance by both Geffen (1973) and Lewin and Associates (1976). However, Blevins, et al. report that a number of light-oil steamflooding projects have been successful in formations with permeabilities as low as 70 md. Therefore, 70 md is taken as the lower limit of permeability for steamflood screening.

- Solution gas drive
- Emulsion drive
- In-situ solvent drive

As steam flows through the reservoir, it transfers heat to formation fluid, reservoir rock, overburden, and underburden. One or more of the listed mechanisms is at work, and various zones or "banks" may be formed. In addition to a steam bank, these may include banks of hot water, light condensate or distillation products, and an oil bank. Usually, the steam bank rises and overrides other formation fluids due to gravity segregation and becomes a "blanket". Oil is then recovered as the steam blanket grows with continued injection. Miller (1984) points out that, unlike other displacement processes, this effect causes most oil recovery during a steamflood to occur after breakthrough of the injected fluid.

A significant difference between steamflooding and the other displacement processes listed in Table 5.1 is that reservoir heterogeneity and the effects of fractures may not be critical factors. The movement of a steam zone tends to be more uniform since any flow channelling through high permeability streaks, or fractures, tends to dissipate due to excessive heat loss to the formation.

Certain screening criteria differ between authors. For the permissible range of API gravity, the more accepted values are between

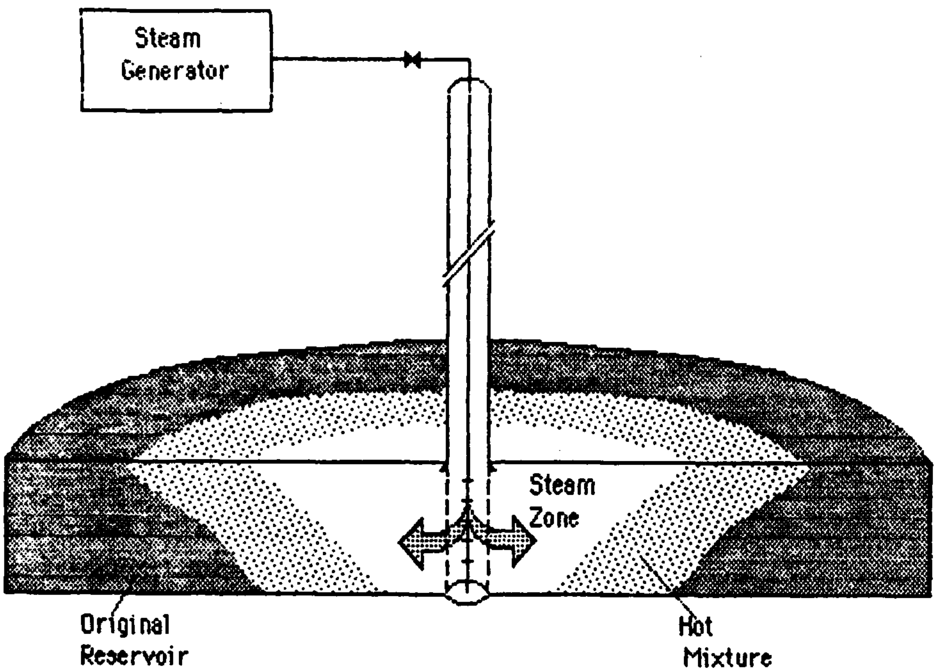

Fig. 5.2. A simplified depiction of the steamflooding process [from Aydelotte and Pope (1983)].

5.4.1 Steamflooding

Figure 5.2 schematically illustrates the steamflooding process. Wu (1977) and Willman, et al. (1961) list the following mechanisms as contributing to improved oil recovery by steam drive:

- Viscosity reduction
- Thermal expansion of oil
- Reduction of residual oil
- Steam distillation
- Gravity segregation

The Shannon appears to meets all EOR screening criteria listed by Taber and Martin for alkaline flooding. However, Owens and Archer (1971) have shown that oil recovery by alkaline waterflooding does not apply unless the acid index is over 0.5 mg KOH/g crude. Samples of Shannon crude were evaluated as having an average acid index of 0.125 mg KOH/g crude. For this reason, it appears that alkaline waterflooding is not a viable EOR process for the Shannon reservoir.

5.3 Hydrocarbon and Other "Gas" Methods

Included in this category are miscible solvent flooding, enriched gas drive, high pressure gas drive, carbon dioxide flooding, acid or flue gas injection, and inert gas injection. These methods recover oil by generating some degree of miscibility. However, all require sufficient depth so that high pressures can be introduced into the formation. Due to the shallow depth of the Shannon formation, none of these processes are applicable.

5.4 Thermal Recovery

Thermal recovery methods consist of steam and hot water injection processes, and in-situ combustion processes. Except for hot water flooding, all thermal recovery methods improve productivity by reducing crude viscosity (Prats, 1982). Other mechanisms may be important, depending upon the process.

It is noted, however, that Smith (1983) states that no surfactant/polymer projects in the United States have ever been reported as being profitable.

Surfactant/polymer flooding merits further investigation. The screening parameters listed in Table 5.1 are satisfied except for the problems which might arise due to the presence of fractures in the formation. If successful, a miscible process such as this could mobilize the large amount of residual oil which would otherwise be left in the reservoir by an immiscible displacement method. High costs of chemicals, complex operating requirements, and the preference for a more homogeneous reservoir are negative factors. For these reasons, surfactant/polymer flooding was judged to have marginal potential for the Shannon formation.

5.2.2 Alkaline Water Flooding

With many oils it is possible to inject a low pH solution to generate an in-situ surfactant. This has the advantage of being less expensive than the petroleum sulfonates, alcohols, salts and other chemicals used in surfactant flooding systems. Ehrlich, et al. (1976) listed the following mechanisms which are possible in oil recovery by alkaline water flooding:

- Solution gas drive
- Emulsification and entrapment of oil for mobility control
- Wettability reversal from oil-wet to water-wet
- Wettability reversal from water-wet to oil-wet

be bypassed. While bedding should be considered in well placement and selection of completion interval, fracture plugging techniques to divert injection flow from high permeability zones may need to be employed.

5.2 Miscible-Type Waterflooding

Miscible-type waterflooding techniques are often referred to as *surfactant floods, micellar floods, microemulsion floods, detergent floods,* and soluble oil floods. For this report, alkaline floods were included in this category. Mobilization of residual oil is the primary purpose of these processes.

5.2.1 Surfactant/Polymer Flooding

A slug consisting of water, surfactant, salt, and possibly an alcohol co-solvent and/or a hydrocarbon is injected in this process. Depending upon surfactant concentration, the slug may be between 5% and 50% of the pore volume. Generally, the smaller slugs utilize higher surfactant concentrations. The surfactant slug is followed by a polymer slug of up to 50% of the pore volume for mobility control. Petroleum sulfonates or blends with other surfactants are most often used. Taber and Martin show that this process recovers oil by:

- Reduction of interfacial tension between oil and water
- Oil solubilization
- Oil and water emulsification
- Mobility enhancement

flexible chains of acrylamide monomers. This gives the disadvantage of making them subject to shear degradation. However, polyacrylamides are relatively immune to bacterial activity and are approximately one-half the price per pound of polysaccharides. Polysaccharides, or biopolymers, are produced by microbial action, and offer the advantages of increased viscosity and shear stability. Also, they are generally more tolerant of poor (saline) waters than are polyacrylamides. However, in addition to higher cost, polysaccharides require the use of oxygen scavengers and bactericides.

In consideration of a polymer flood for the Shannon, it was noted that both the poor mobility ratio to be expected and the presence of fractures in some parts of the formation are unfavorable factors. Also, the large polymer molecules may plug low permeability zones. Channelling problems which might arise may be corrected by fracture plugging treatments. For example, Mack and Warren (1984) reported on a successful polymer flood in which such diversion was used at the Sage Spring Creek Unit. In this project, cationic and anionic polyacrylamides were injected with aluminum citrate into fractured Dakota sandstone. Whether plugging of low permeability zones will be significant in the Shannon sandstone is subject to field testing.

Based on the screening criteria listed in Table 5.1, polymer flooding appears to be a viable candidate for application in the Shannon. The drawbacks to using this method concern the physical makeup of the reservoir - bedding and fractures. Both factors may cause portions of the formation to

The results of the water flood performed in the East Teapot Field portion of the Shannon, as well as the bedding characteristics of the reservoir, both discussed earlier, imply that mobility control is necessary. This was confirmed by Core Laboratories', Inc. (Nov. 1978) core analysis in which relative permeability relationships were determined for the Shannon. These data give a range of mobility ratios from M = 3.5 to M = 209. An adverse mobility ratio of M = 68 was calculated using average values.

5.1.1 Polymer Flooding

In polymer flooding, water soluble polymers are added to injection water to increase viscosity and thus reduce the mobility ratio. Commonly, a polymer "slug" of 15 to 25 per cent of the pore volume is injected, followed by water injection. These polymers are generally high in molecular weight and composed of long-chain molecules. This has the advantage of increasing injection water viscosity and in some cases changing oil-water permeabilities. Additionally, cross-flow from low to high permeability zones increases the effectiveness of this process by plugging the the high permeability flow channels. However, a possible disadvantage is that the relatively large molecules may plug low permeablitity zones.

Polymer flooding is usually conducted using either polyacrylamide or polysaccharide polymers. Polyacrylamides are employed in about 80 per cent of all projects [Smith (1983)], and have the advantages of both viscosity increase and relative permeability alteration. They are composed of long,

Caudle shows that a mobility ratio of greater than 1 is unfavorable to efficient displacement since flow of the displacing phase, be it water or some other fluid, would be preferred over that of the oil. The effect of mobility ratio on areal sweep is depicted in Fig. 5.1. The mobility ratio may be improved (decreased) by adjusting one or more of the parameters of Eq. 5.1 to make fluid flow such that it will be more uniform, so that greater portions of a reservoir will be contacted at earlier times, sooner displacing more oil. Improved waterflooding methods attempt to accomplish this by raising the viscosity of the injection water and/or reducing the formation's permeability to water.

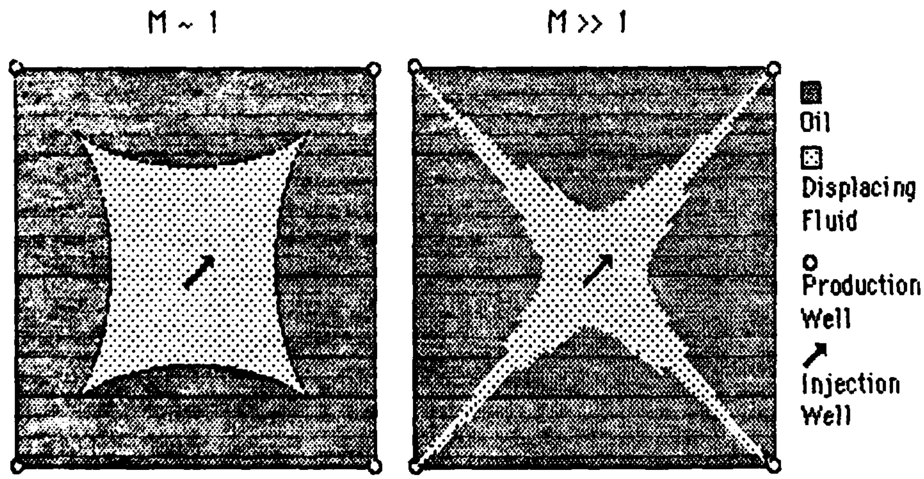

Fig. 5.1. A generalized depiction of the effect of Mobility Ratio, M, on the flow of an injected fluid which is meant to displace oil toward production wells.

- Thermal Recovery
- Mining and Extraction

These categories are composed of various processes. Following is a discussion of the processes, screening criteria, and applicability for the Shannon formation.

5.1 Improved Waterflooding

Conventional waterfloods comprise the majority of injection systems, yielding recoveries (including primary recovery) of from less than 10% to as high as 70% of the original oil-in-place [Smith (1983)]. In waterfloods, injected fluid sweeps through a portion of the formation, displacing mobile oil at some efficiency. Improved waterflooding techniques increase sweep efficiencies in waterfloods by reducing the mobility ratio. The mobility ratio, M, for a water flood is defined by Caudle (1968) "... as the ratio of the fluid mobility (λ_w) in the watered out (swept) region to the fluid mobility (λ_o) in the uninvaded region":

$$M = \lambda_w/\lambda_o = (k_w/\mu_w)/(k_o/\mu_o) \qquad 5.1$$

$$\lambda = k/\mu \qquad 5.2$$

where

k_w = average permeability of the swept region to the displacing fluid

μ_w = viscosity of displacing fluid

k_o = average permeability of the uninvaded region to oil

μ_o = viscosity of oil

oil of 20 °API or greater) are underway in the United States. For example, Dobson and Seelye (1982) describe the successful operation of one such project which was performed in the Tisdale Field, near NPR-3, by Conoco, Inc. Additionally, steam injection via horizontal boreholes is being used in the Kern River field near Bakersfield, CA [Oil and Gas Journal (August 23, 1983)] and in the Yarega Field near Ukhta, USSR [Turner (1984)].

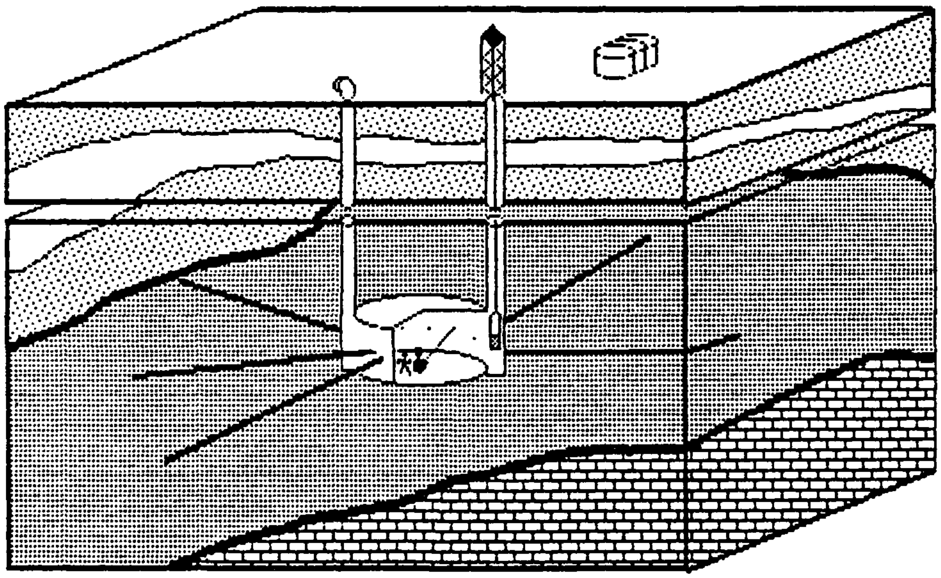

Fig. 5.4. Horizontal drilling from a subsurface drilling room.

Based on the screening criteria, both gravity drainage and steam injection via horizontal boreholes appear to be recovery mechanisms which may be applicable to the Shannon formation and which warrant further investigation.

Table 5.2 Results of EOR Screen

Category	Process
Favorable	Polymer Flooding Steamflooding Horizontal Drilling
Marginal	In-Situ Combustion Surfactant/Polymer Flooding
Unfavorable	Miscible Gas Drives Alkaline Flooding

6. PERFORMANCE PREDICTIONS

Results obtained from the three EOR predictive models used in this study are presented in this chapter in terms of oil produced versus time. Economic analyses are presented in Chapter 7. For each method investigated, predicted production rates and cumulative production for base cases of a 10-acre and a 2.5-acre 5-spot pattern are shown. Results of sensitivity analyses found to be significant are also presented.

6.1 Assumptions Common to All Models

Although there exists a degree of uncertainty regarding some physical properties of the Shannon formation, it is possible to describe the reservoir in terms of a number of average properties. For the purpose of these predictions, the Shannon formation was characterized as a single, homogeneous, continuous sand body of constant thickness, porosity, and fluid saturation. While these assumptions are not generally valid for any reservoir, they are necessary for application of the predictive models used, and were made in the hope that results based on average physical properties would yield an approximation of actual performance. Further, sensitivity analyses for various physical parameters were performed in order to compensate for both the lack of knowledge concerning the Shannon formation, and any actual variability in these properties within the reservoir. Thus, the reservoir was characterized as having the average properties which are described in Chapter 2 and given in Table 6.1.

Table 6.1. Physical Property Assumptions Common to all Predictions

Reservoir Properties	
Reservoir Depth	550 ft
Reservoir Temperature	65 °F
Reservoir Pressure	70 psia
Net Pay Thickness	76 ft
Gross Pay Thickness	96 ft
Rock Properties	
Porosity	19.8 %
Permeability*	200 md
Oil Saturation	45 %
Water Saturation	55 %
Gas Saturation	3 %
Fluid Properties	
Oil Viscosity*	10 cp
Oil Gravity	32 °API
Water Viscosity	1 cp
Solution Gas/Oil Ratio	32 SCF/STB

* Varied in Sensitivity Analyses

6.2 Base Case

To provide for comparison of the predictions for the various cases considered, a base case was established. The unit investigated is a 10-acre 5-spot pattern of wells since the Shannon formation is essentially fully developed in this manner. In this configuration, the only new wells to be drilled would be injectors. Additionally, the existing collection system would be adequate. Limited infill drilling to 2.5-acre spacing has been done at NPR-3. As illustrated in Fig. 6.1, this allows for the inclusion of existing wells in a uniform pattern. Thus, a second base case is considered for each process,

using a 2.5-acre well pattern. However, sensitivity analyses were done only for the 10-acre base case. Reconfiguration to 5-acre spacing could also be accomplished utilizing existing wells, but was not considered in this study.

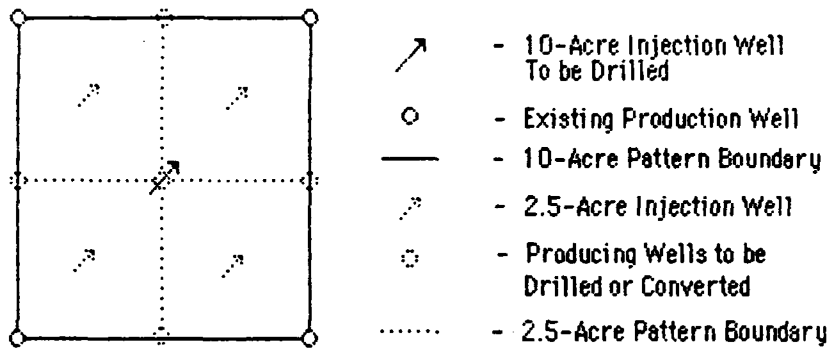

Fig. 6.1. An illustration of a 10-acre 5-spot pattern, which is the basic unit investigated in this study. Also shown is the manner in which infill drilling to 2.5-acre spacing could be accomplished.

Performance predictions are given in the following sections for various cases. Production rate is expressed in BOPD and cumulative production is shown in MSTB.

6.3 In-Situ Combustion Prediction

Figures 6.2 and 6.3 give the results of the base case predictions obtained from Genrich's in-situ combustion model for the 10-acre and 2.5-acre base cases, respectively. Figure 6.4 compares cumulative production for the two cases on a 10-acre basis, i.e. four 2.5-acre 5-spot patterns. Ultimate recovery for the 10-acre base case is 256.8 MSTB, or approximately 49% of the oil in place, and ultimate recovery for four 2.5-acre patterns is 276.7 MSTB, or 53% of the oil in place. The production rate curves of Figs. 6.2 and 6.3 show

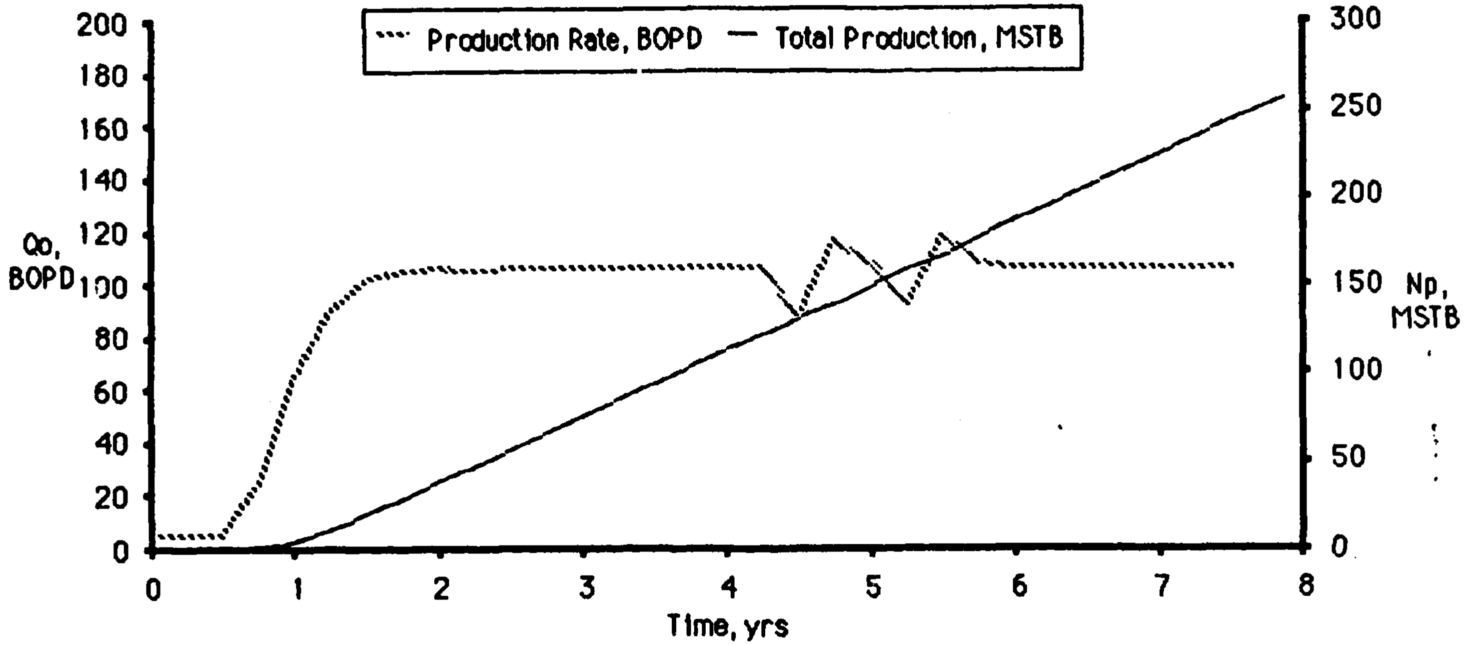

Fig. 6.2. In-Situ Combustion 10-Acre Base Case

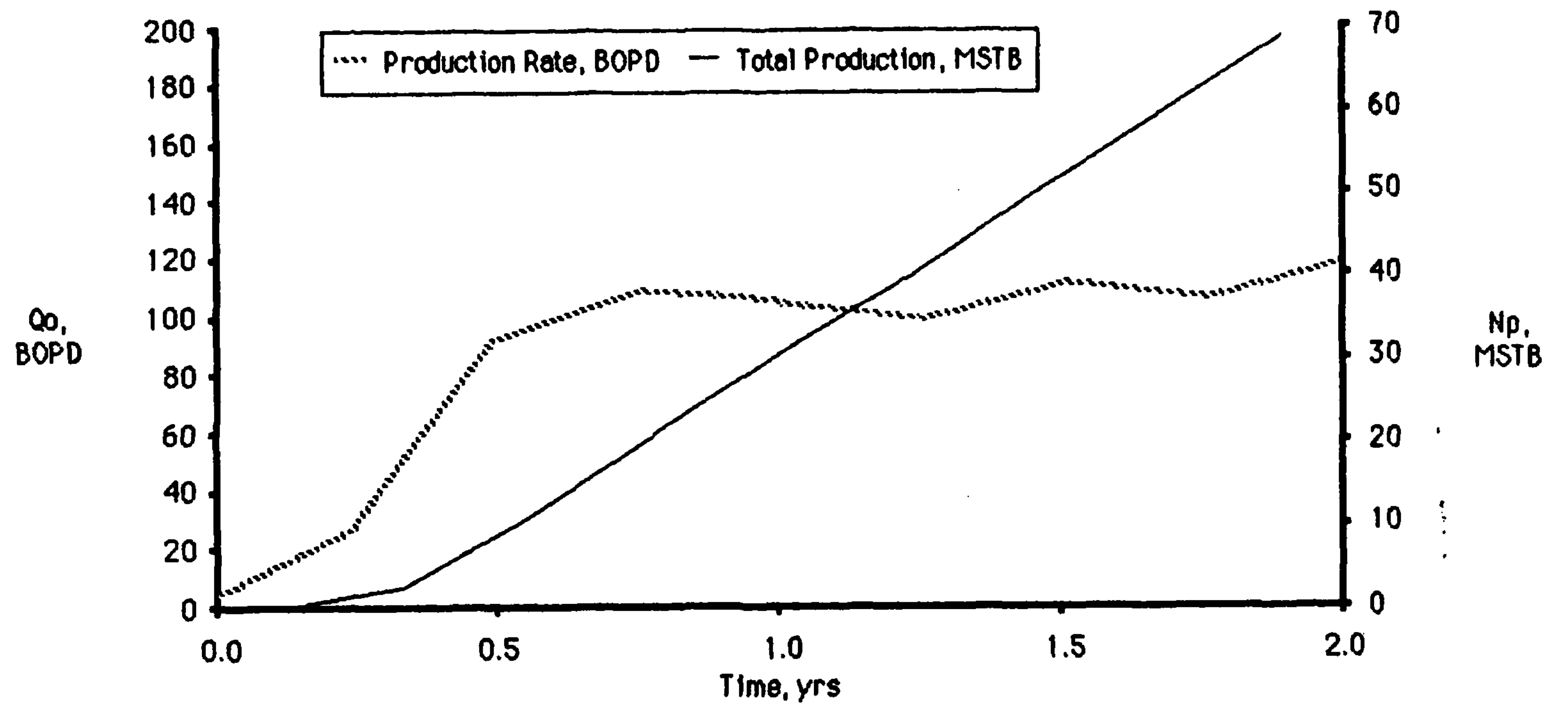

Fig. 6.3. In-Situ Combustion 2.5-Acre Base Case

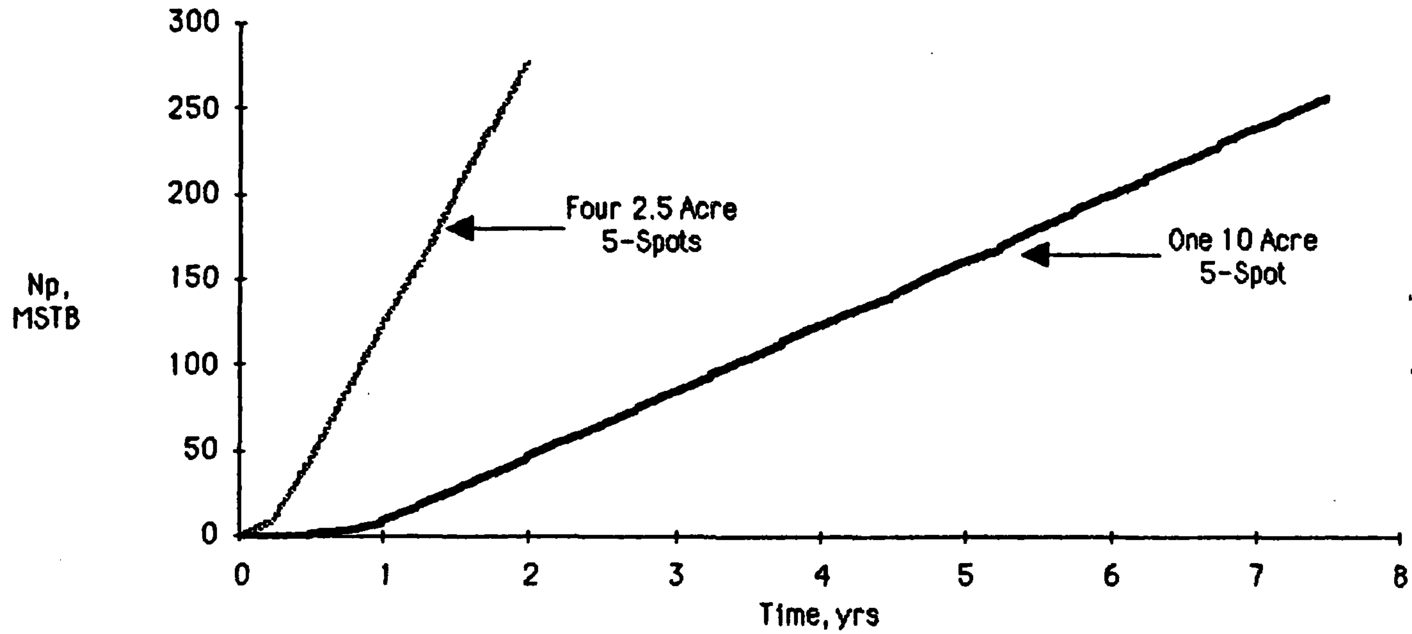

Fig. 6.4. Effect of Pattern Size on In-Situ Combustion

that the model does not predict a production decline, but rather a "plateau" of approximately 105 BOPD which is abruptly stopped, presumably because of predicted combustion front arrival at the producing well. Additionally, predicted production was oscillatory between years four and six. The reason for this behavior was unknown.

The lack of a production decline was shown in all cases investigated. The termination of production was that predicted by the model, and not an economic limit. This was not well understood and it appeared to be unrealistic. For example, varying air injection rates resulted in predictions which implied that the ultimate cumulative production would be different. It was felt that in a case such as this, ultimate cumulative production should be identical for different air injection rates, and only recovery time would vary. Further, this character does not agree well with examples of actual in-situ combustion project production histories given by Prats (1982). However, at least one field project, at West Newport, CA, did exhibit an extended period of steady production, as is implied for the Shannon formation by Genrich's model.

In addition to the properties given in Table 6.1, equivalent fuel saturation and oxygen consumption efficiency were specified, based on the results of combustion tube experiments performed by Core Labs [May, 1980] Default values calculated by Genrich's model were used for the other optional parameters listed in Appendix 10.1.1. The base case air injection rate was taken to be 850 thousand cubic feet per day (MCFD), based on actual practices in the Shannon formation in-situ combustion pilot project in November 1984 [Grooms (1984)].

Oxygen consumption efficiency was taken to be 88% for all predictions made in this study, also based upon the combustion tube experiment results. The effect of air injection rate upon predicted performance was measured by choosing a low rate of 500 MCFD and a high rate of 1200 MCFD. Sensitivity to permeability and viscosity were also examined, and it was shown that neither parameter altered predictions measurably from the base case. Permeability changes showed no changes from base case predictions, while the use of 7 cp and 20 cp oil as an input parameter resulted in changes from the base case of approximately 1%.

Additionally, injected oxygen concentration was studied, using values of 30 weight per cent and 50 weight per cent oxygen. Genrich allowed for both oxygen weight per cent and mole per cent to be specified as input parameters. However, it was found that the model did not respond to changes in oxygen mole per cent as an input variable, which would have been easier to analyze from the standpoint of stoichiometry. Therefore only oxygen weight per cent was varied as an input parameter.

6.3.1 Effect of Equivalent Fuel Saturation

It was found that the most significant optional parameter for input into Genrich's model was equivalent fuel saturation, S_{OF}, for which the default value was zero. As given by Prats (1982) for calculation of S_{OF} from a combustion tube test, S_{OF} is defined as:

$$S_{oF} = m_R/\phi\rho_o \quad \text{6.1}$$

$$m_R = m_E(1-\phi)/(1-\phi_E) \quad \text{6.2}$$

where,

ϕ	=	Porosity of the reservoir, fraction
ϕ_E	=	Porosity of the combustion tube material, fraction
ρo	=	Oil density, lb_m/ft^3
m_R	=	Mass of reservoir fuel burned, lb_m/ft^3
m_E	=	Mass of combustion tube material burned, lb_m/ft^3

Figure 6.5 illustrates the predicted importance of equivalent fuel saturation to in-situ combustion performance. This figure shows that if the equivalent fuel saturation were as low as 3.5%, recovery would be over 12% greater than the base case in a four-year vice eight-year project life. Conversely, if equivalent fuel saturation were 18.7%, ultimate recovery from the project would be only about 25% of the base case in essentially the same project life. This is not a parameter which can be optimized, rather it is a property of the reservoir fluid. However, this analysis indicates the importance of quantifying equivalent fuel saturation.

6.3.2 Effect of Air Injection Rate

Figure 6.6 shows the effect of air injection rate upon predicted in-situ combustion performance in the Shannon formation. As expected, higher injection rates are predicted to give significant improvements in performance. However, as noted previously, the results from the model also inferred that ultimate recovery would change, which was not expected. Compared with the base case recovery prediction of 256.8 MSTB, or approximately 49% of the oil in place, the prediction for 500 MCFD gives an ultimate recovery of only 140.4MSTB, or 27% of the oil in place. Recovery for an air injection rate of 1200 MCFD indicates an ultimate cumulative

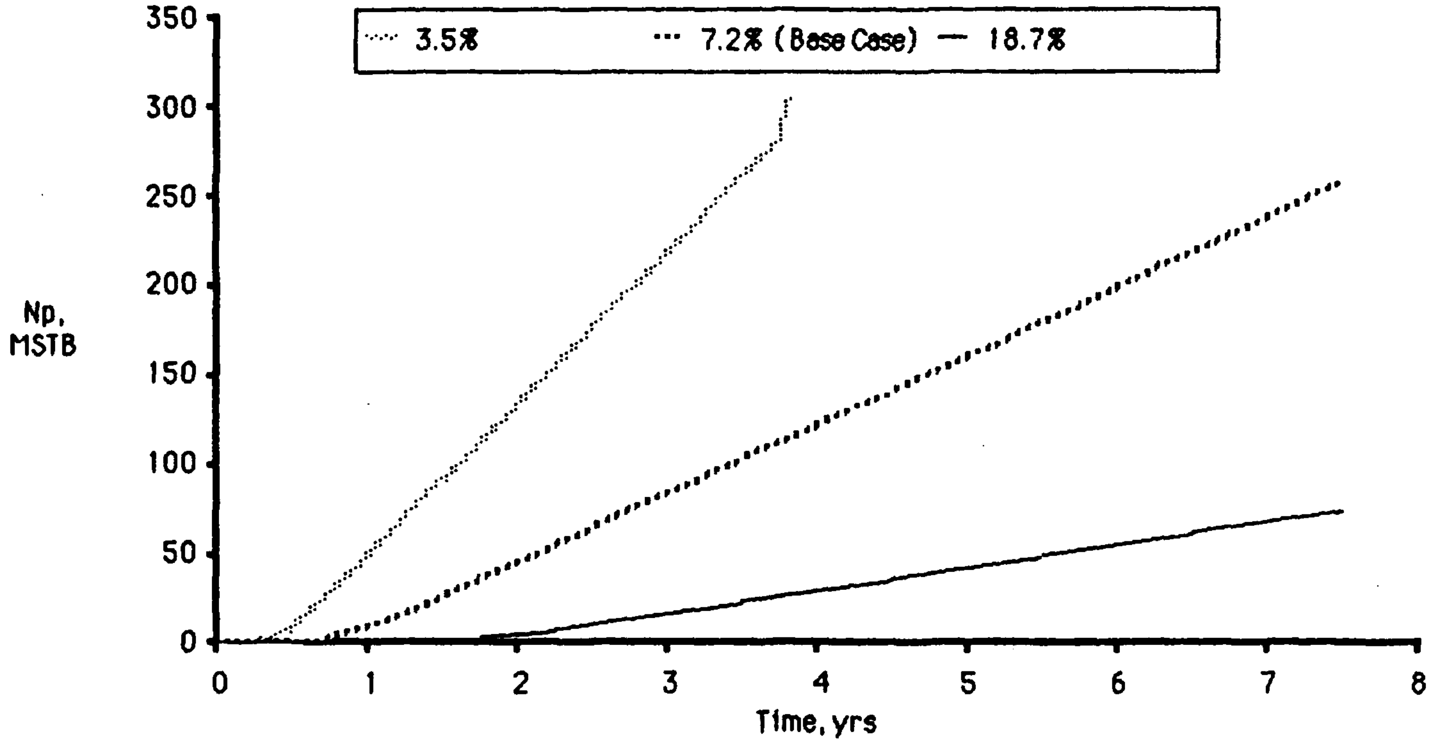

Fig. 6.5. Effect of Eq. Fuel Saturation on In-Situ Combustion

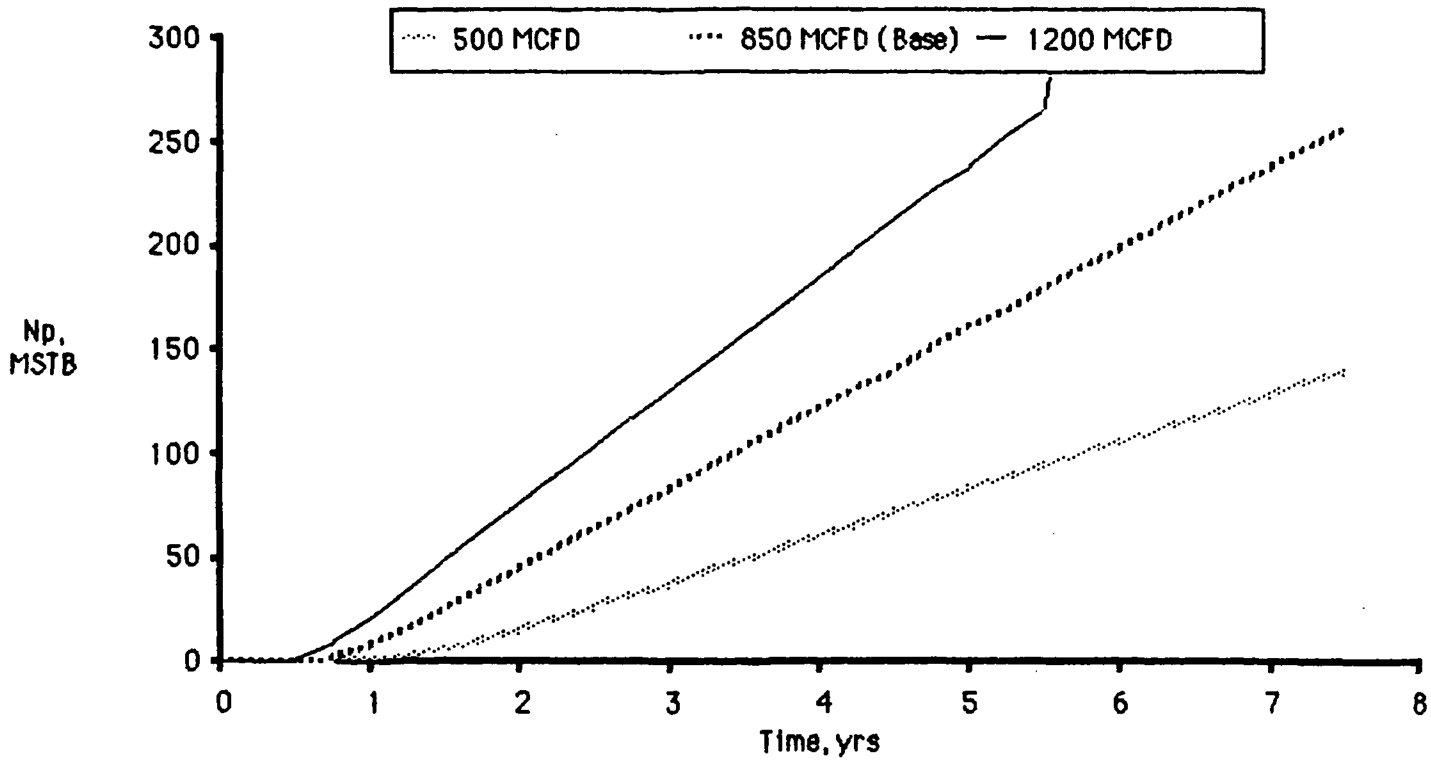

Fig. 6.6. Effect of Injection Rate on In-Situ Combustion

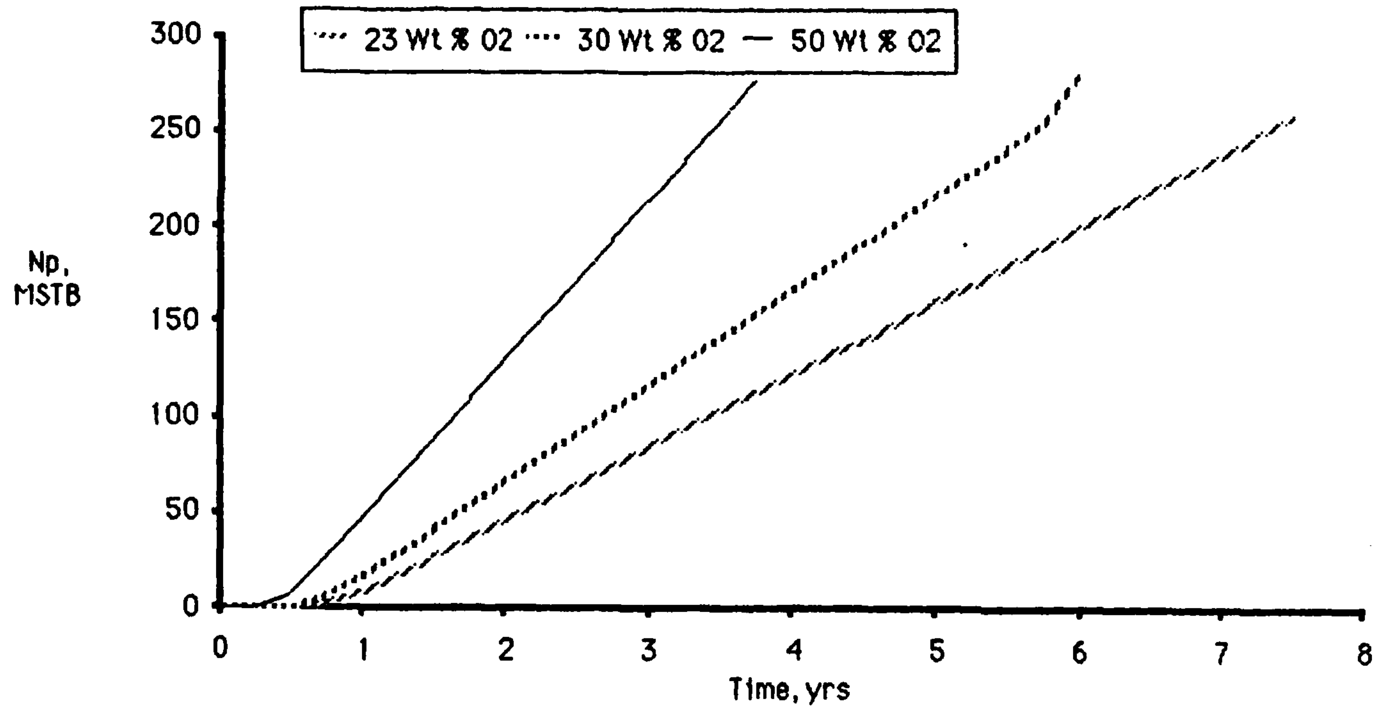

Fig. 6.7. Effect of Oxygen Concentration on In-Situ Combustion

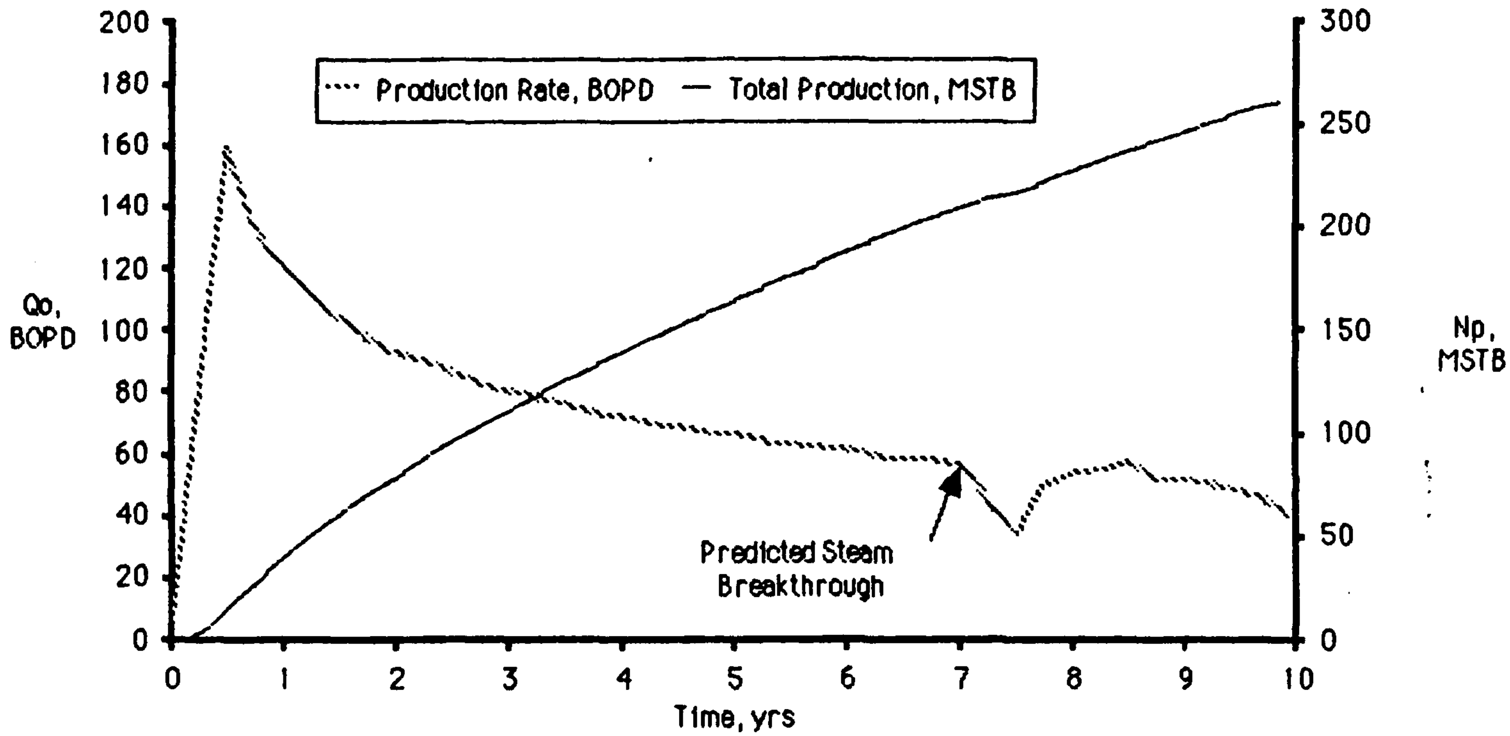

Fig. 6.17. Steamflood 10-Acre Base Case

In addition to the properties given in Table 6.1, equivalent fuel saturation and oxygen consumption efficiency were specified, based on the results of combustion tube experiments performed by Core Labs [May, 1980] Default values calculated by Genrich's model were used for the other optional parameters listed in Appendix 10.1.1. The base case air injection rate was taken to be 850 thousand cubic feet per day (MCFD), based on actual practices in the Shannon formation in-situ combustion pilot project in November 1984 [Grooms (1984)].

Arima's prediction modelled base case results for a steamflood in the Shannon formation as shown in Figs. 6.17 and 6.18 for 10-acre and 2.5-acre spacing, respectively. Figure 6.19 compares the results of cumulative production on a 10-acre basis. All predictions exhibited the character of high initial production followed by a steady decline. As noted in Fig. 6.17, steam breakthrough is not predicted to occur until late in project life. Due to the heterogeneity of the Shannon reservoir, steam breakthrough would probably occur much sooner than is predicted by Arima.

6.5.1 Effect of Injection Rate

Figure 6.20 shows that injection rate is predicted to have a substantial effect on steamflood performance, with a rate of 700 BSPD yielding twice the recovery of a 300 BSPD injection rate in a 10-year period. However, additional recovery must be weighed against the commensurate steam generation costs. It should also be noted that Arima's predictive model gives which is based upon frontal displacement. Although the

slightly higher flow rates early in the project, the 250 lb/ac-ft upper limit value showed better production performance thereafter.

6.4.4 Effect of Polymer Concentration

The analysis of polymer concentration found that an increase in concentration yielded a corresponding increase in predicted early oil production, as shown in Fig. 6.15. As with oxygen concentration for the case of in-situ combustion, the choice of polymer concentration is ultimately an economic decision.

6.4.5 Effect of Polymer Slug Size

Figure 6.16 shows that Jones' model predicted virtually no difference in performance when three different slug sizes were evaluated. It is noted on Fig. 6.16 that the 0.25 PV slug shows a better recovery than the other two cases at about 7 years, when it reaches its economic limit of WOR = 50. This increase in production was evidently the result of substantially higher predicted water injection rates for the 0.25 PV case.

6.5 Steamflood Prediction

Additional base case data for the steamflood prediction included steam quality, injection rate, injection pressure, and thermal properties of the reservoir. Surface steam quality was estimated to be 80% and injection rate was taken to be 500 bbls of steam per day (BSPD), expressed in equivalent barrels of cold water. The injection pressure used was 500 psia, and thermal properties of the formation were taken from a study of the Shannon formation by Zargarnian (1984).

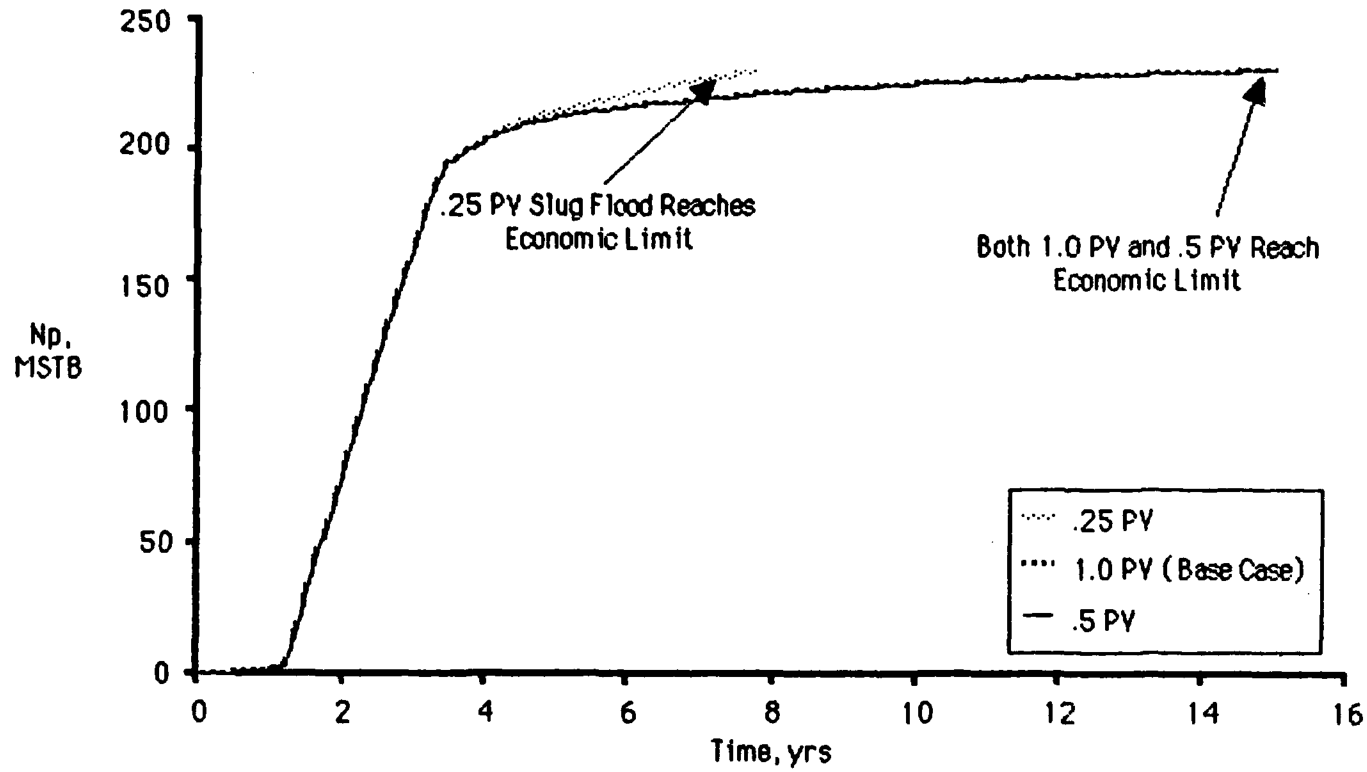

Fig. 6.16. Effect of Slug Size on Polymer Flood

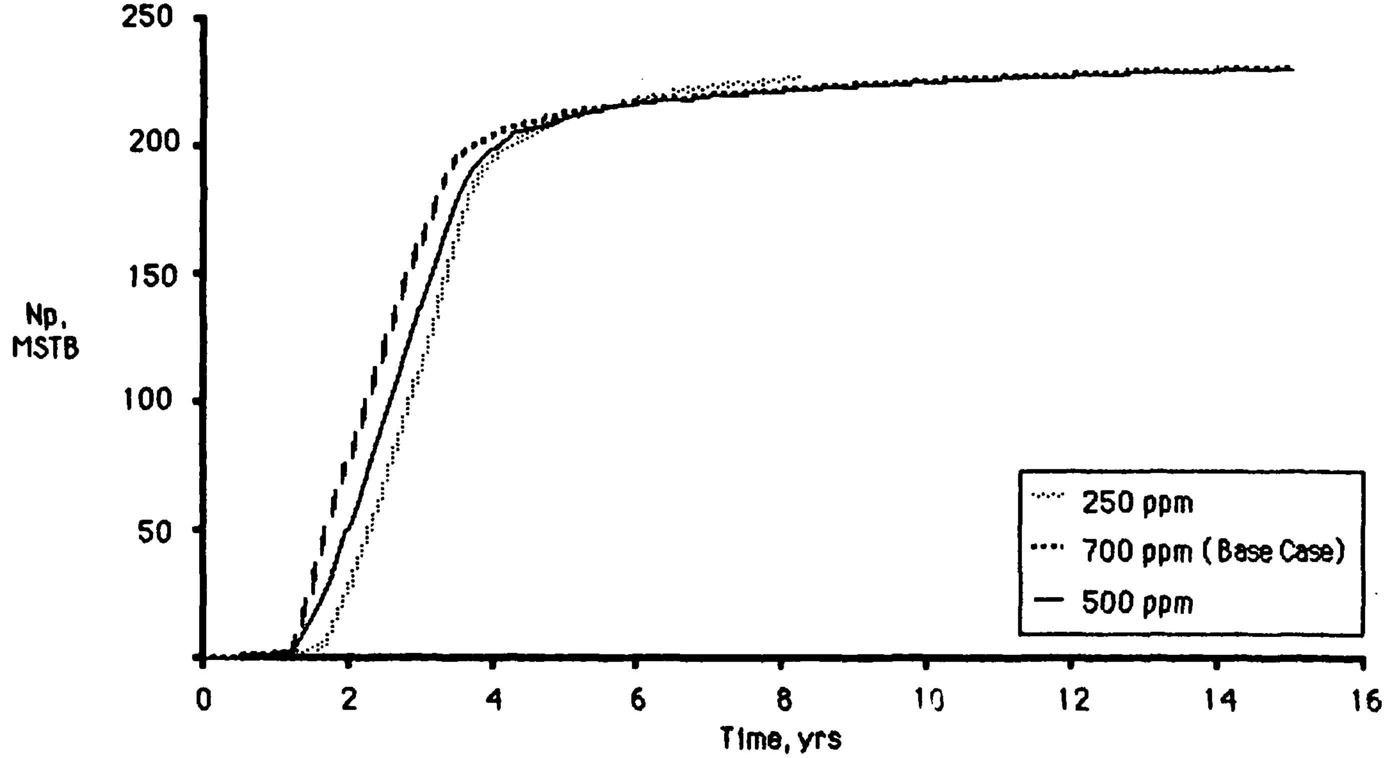

Fig. 6.15. The effect of Polymer Concentration on Polymer Flood

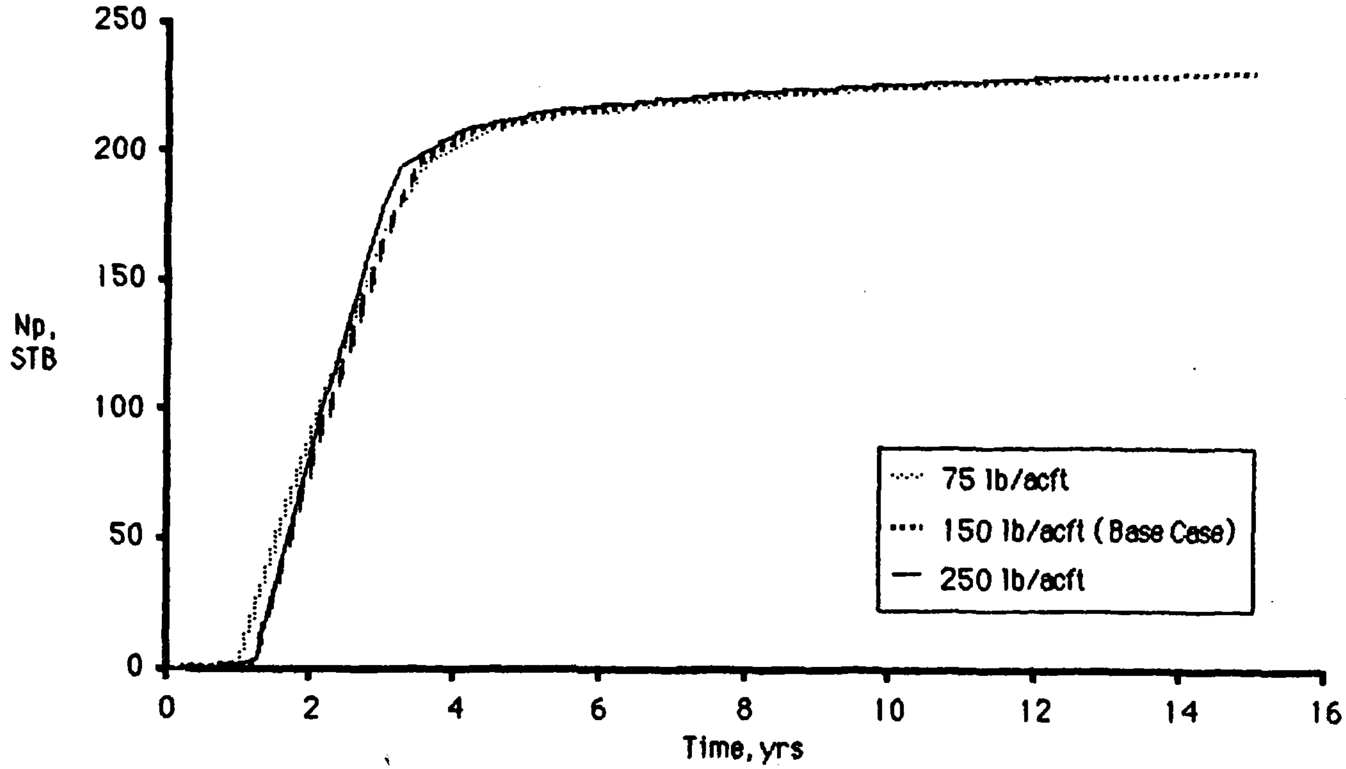

Fig. 6.14. Effect of Polymer Adsorption on Polymer Flood

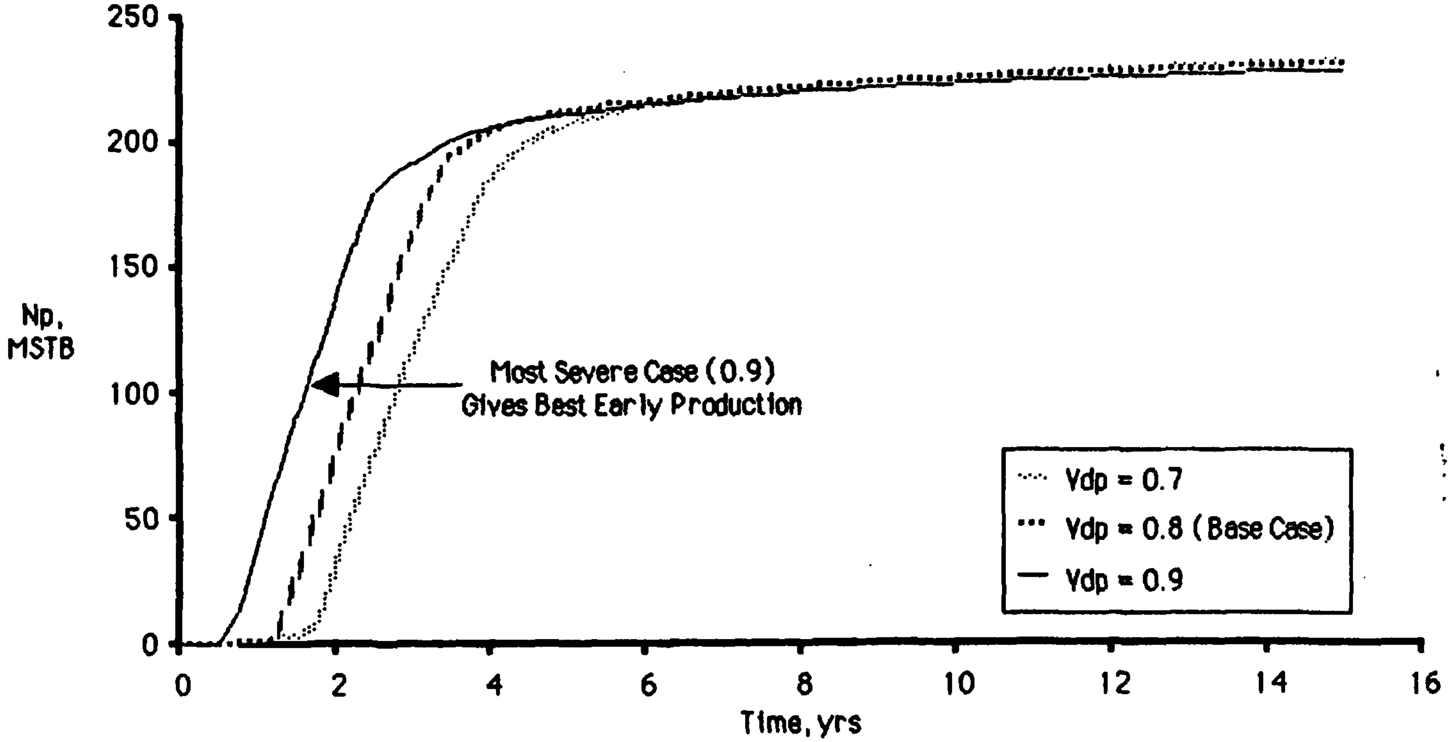

Fig. 6.13. Effect of Permeability Variation on Polymer Flood

production for 2 years compared to the base case of 10 cp oil. As discussed in Chapter 2, there appears to be either variability of this property within the Shannon formation or measurement inaccuracies. This analysis illustrates that oil viscosity is a critical physical variable and that it requires more extensive and exacting analysis before economic decisions would be made regarding polymer flooding.

6.4.2 Effect of Permeability Variation

As with oil viscosity, permeability variation is not a variable that can be changed. But it is a characteristic of the Shannon formation that is not well understood and was therefore investigated for its effect upon predicted polymer flood performance. The Dykstra-Parsons permeability variation V_{DP}, as described by Caudle (1968), is used by Jones to statistically simulate flow as occurring in a number of layers. Figure 6.13 shows that the most severe case considered, V_{DP} = 0.9 yielded the best performance in terms of earliest production. This was somewhat surprising as a more heterogeneous reservoir would tend to promote by-passing of fluids into high-permeability zones, away from low-permeability areas, thus hindering effective production.

6.4.3 Effect of Polymer Adsorption

Polymer adsorption was thought to be a potentially critical variable with regard to prediction of polymer flood performance and was thus analyzed. As shown in Fig 6.14, Jones' model does not indicate that within the range of values tested that the effect of this parameter will be significant. However, the results of this analysis are presented for completeness. It is interesting to note that while the lower value tested, 75 lb/ac-ft, predicted

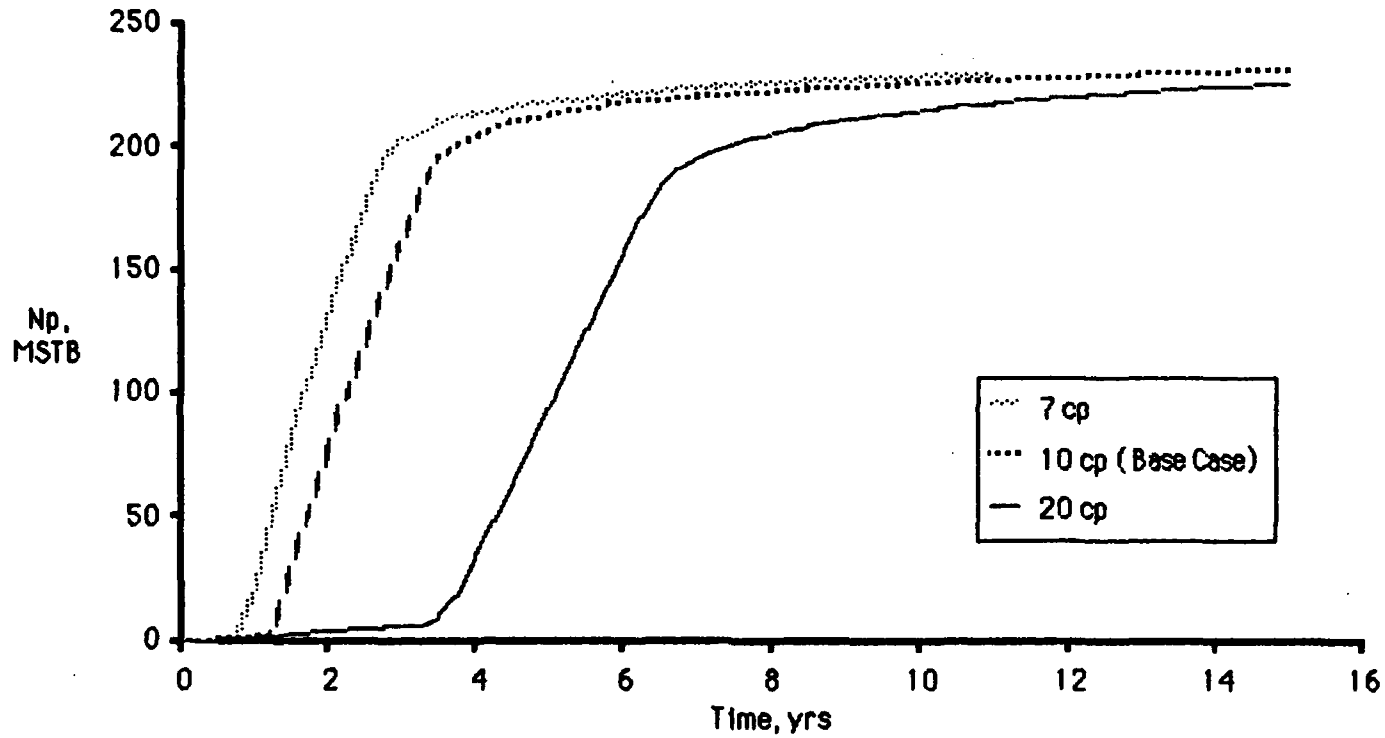

Fig. 6.12. Effect of Oil Viscosity on Polymer Flood

production followed by a period of high but rapidly declining production. Figure 6.11 shows polymer injection requirements predicted by the model. In discussing predicted ultimate recoveries in this section, an arbitrary cut-off point of a water-oil ratio (WOR) of 50 was chosen; for reference, Caudle (1984) suggests a WOR of 20 as an economic limit. An ultimate recovery of 222.9 MSTB, or 43% of the oil in place is predicted for the 10-acre pattern, while four 2.5-acre patterns were predicted to produce 230.4 MSTB, or 44% of the oil in place.

Parameters additional to the base case which were applied to the polymer flood prediction included polymer properties, polymer slug size, polymer concentration, and injection pressure. Dow Pusher 700 was chosen as a representative polyacrylamide polymer and its properties were those used in all predictions. The base case also considered polymer to be injected at a concentration of 700 ppm in a slug of 1.0 pore volume (PV). Polymer concentration and injected pore volumes were both analyzed for their effect on performance prediction. An injection pressure of 500 psi was used in all predictions, as pressures of this magnitude are presently being used in the Shannon formation pilot tests [Schulte (1984)]. Finally, polymer adsorption of 150 lb/ac-ft was specified for base case predictions, and was varied in a sensitivity study.

6.4.1 Effect of Oil Viscosity

Unlike the in-situ combustion prediction, varying oil viscosity as an input parameter had a dramatic effect on performance prediction. As shown in Fig. 6.12, an oil viscosity of 20 cp effectively delays any significant

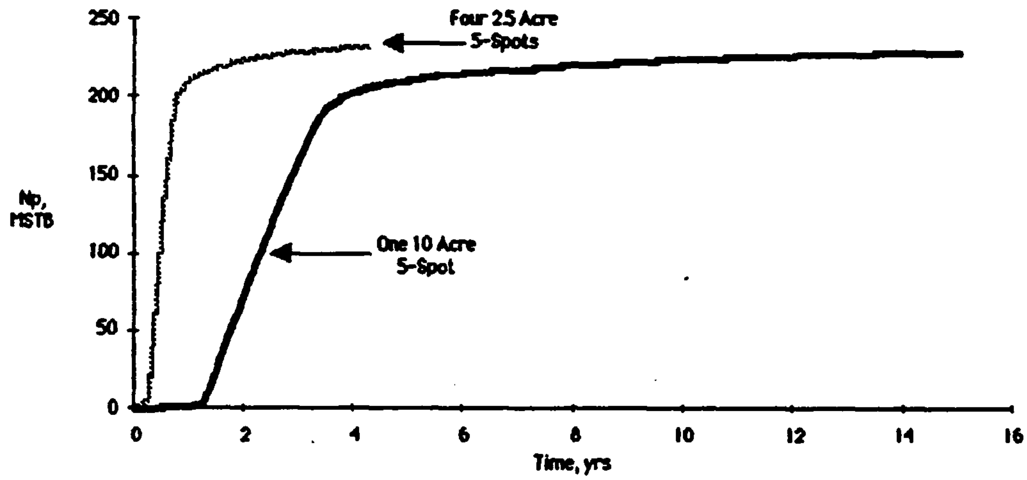

Fig. 6.10. Effect of Pattern Size on Polymer Flood

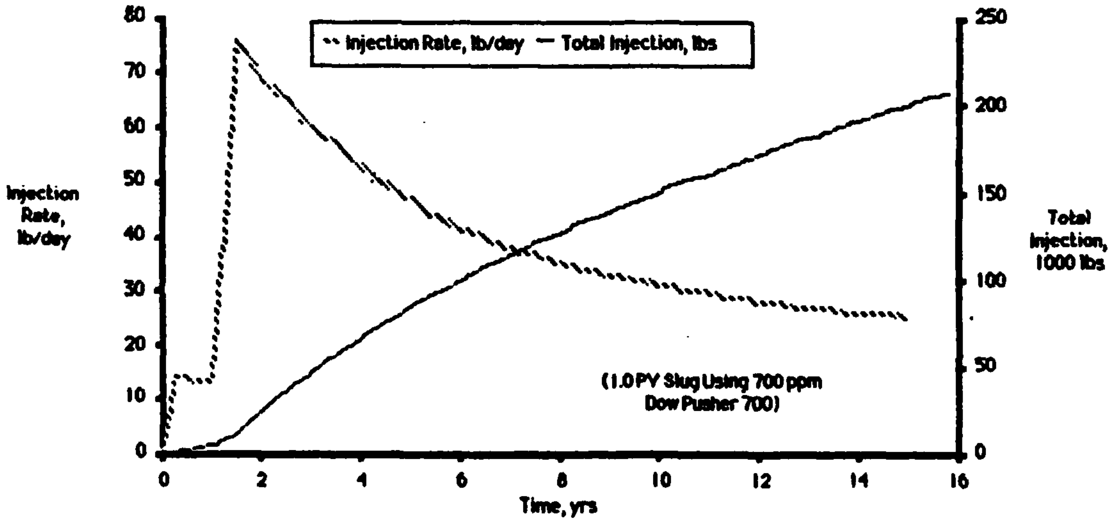

Fig. 6.11. Polymer Injection Schedule for 10-Acre Base Case

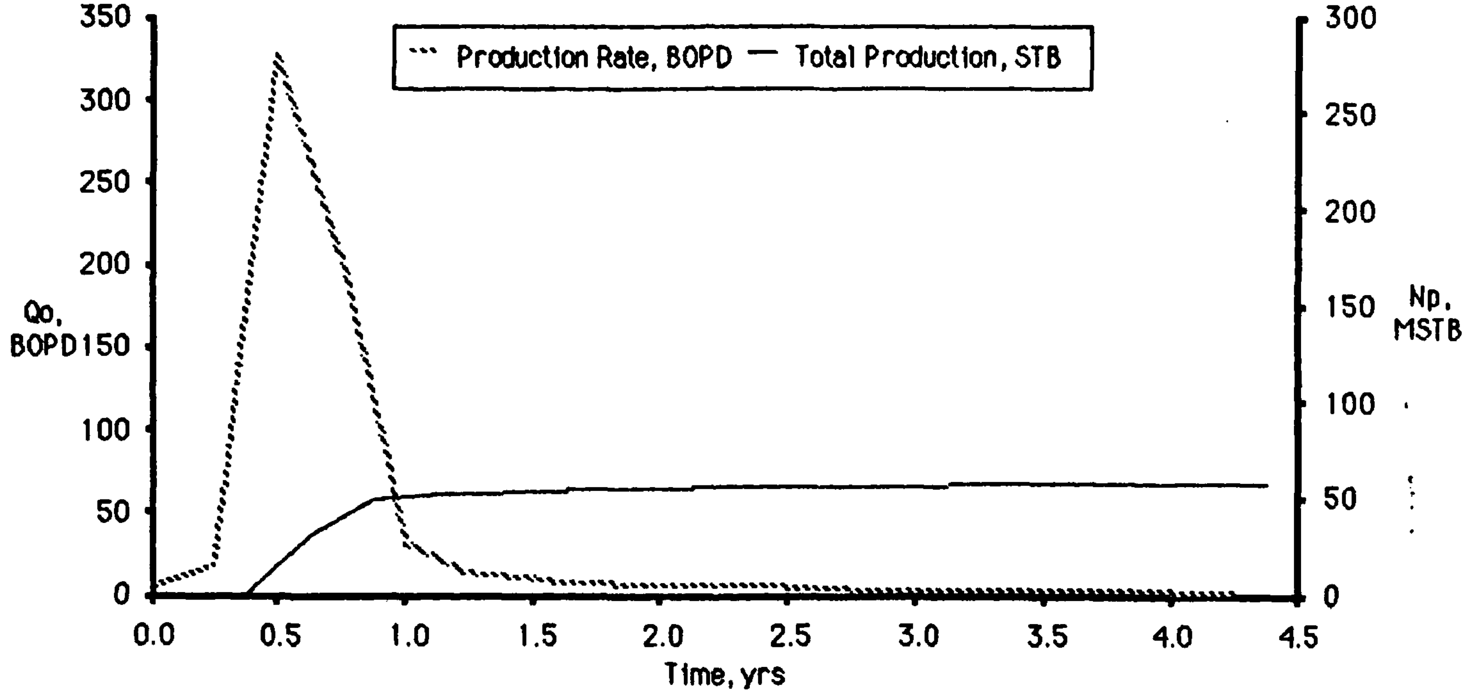

Fig. 6.9. Polymer Flood 2.5-Acre Base Case

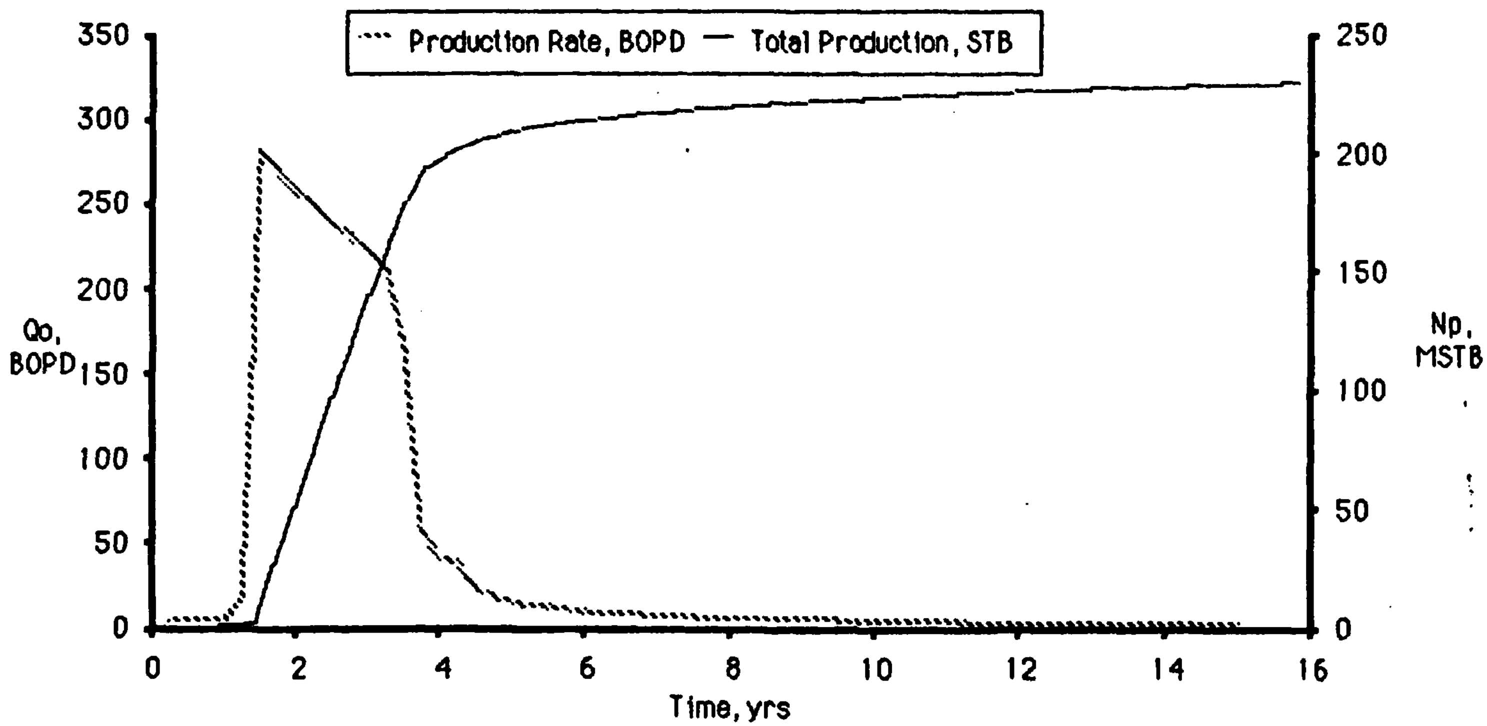

Fig. 6.8. Polymer Flood 10-Acre Base Case

production of 281.8 MSTB, or 54% recovery. While the effect of air injection rate upon ultimate recovery appears questionable, production rates were as expected, i.e., lower production rates resulting from lower injection rates. The choice of an optimum injection rate is an economic one, requiring further analysis as is done in Chapter 7.

6.3.3 Effect of Oxygen-Enriched Air

Like air injection rate, the oxygen content of injected air is an economic decision factor, requiring the consideration of special safety measures and extra equipment, but also of lower air compression costs. Figure 6.7 gives the predicted performance of in-situ combustion in the Shannon reservoir using oxygen-enriched injection air. In this analysis, injection rate was held constant at 850 MCFD in order to provide a simplified comparison with the base case. A more complete study should determine what injection rate would yield a specified recovery, in order to compare capital and operating expenses on that basis. Raising the weight per cent of oxygen to 30% yields slightly better predicted recovery while decreasing project life by 1.5 years. The effect of raising the oxygen concentration to 50% does not raise ultimate recovery above the 30 weight per cent case, however it lowers project life even more, to 3.7 years.

6.4 Polymer Flood Prediction

Base case predictions obtained from Jones' polymer flooding predictive model are given in Figs. 6.8 (10-acre) and 6.9 (2.5-acre), and compared on a 10-acre basis in Fig. 6.10. As in all polymer flood predictions which were made, both base cases are characterized by a short period of low

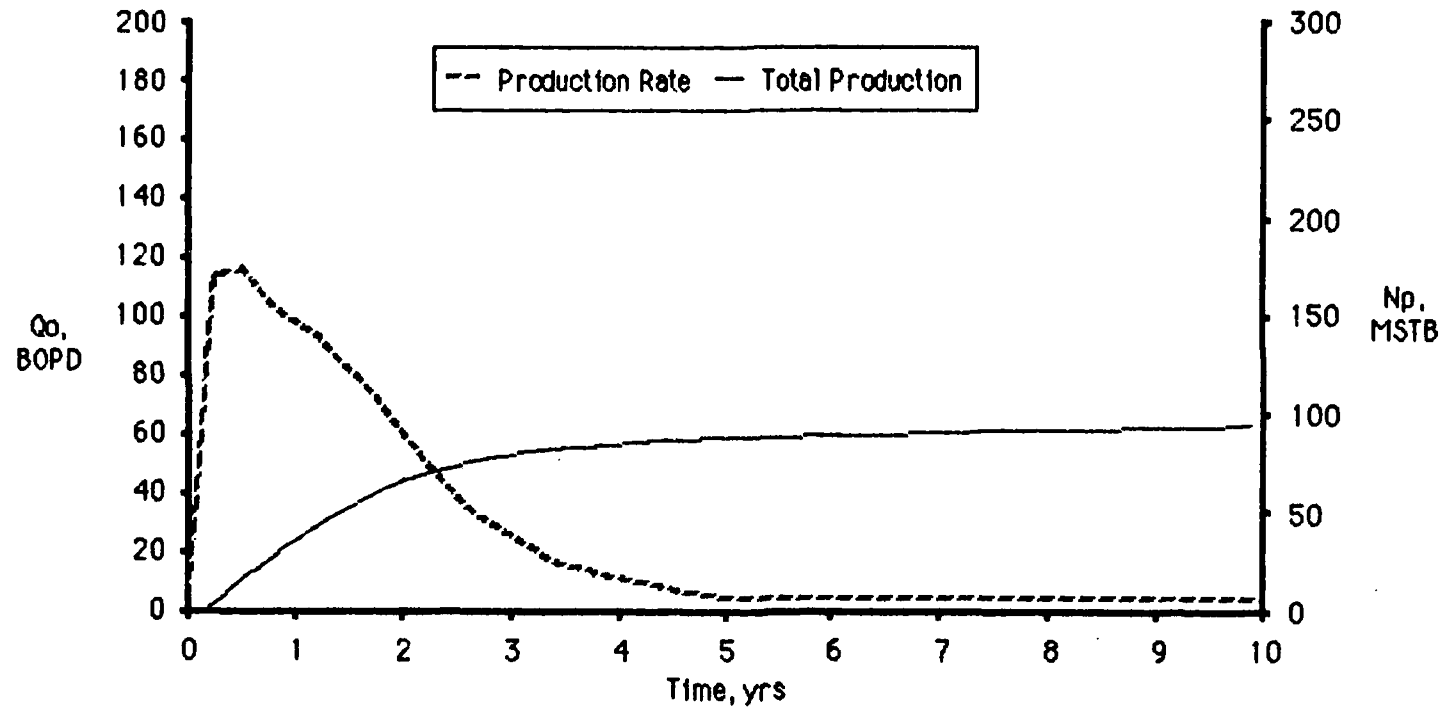

Fig. 6.18. Steamflood 2.5-Acre Base Case

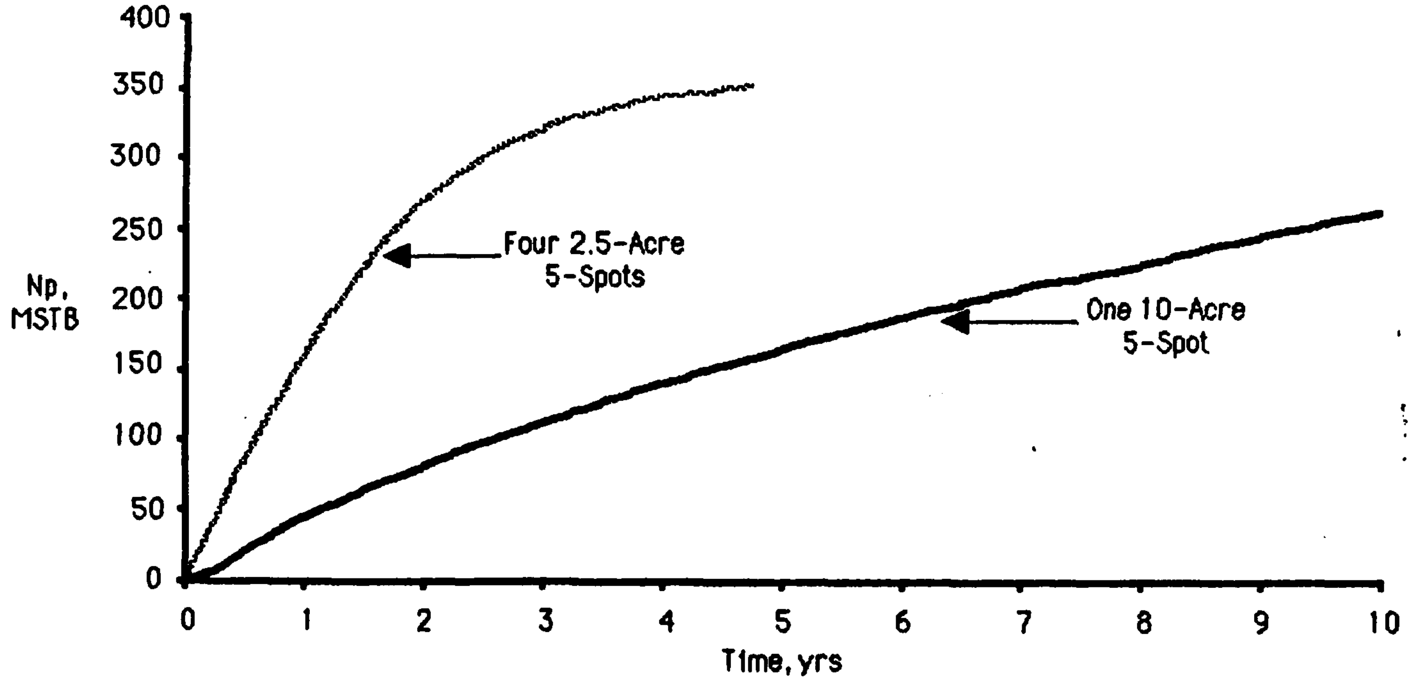

Fig. 6.19. Effect of Pattern Size on Steam Flood

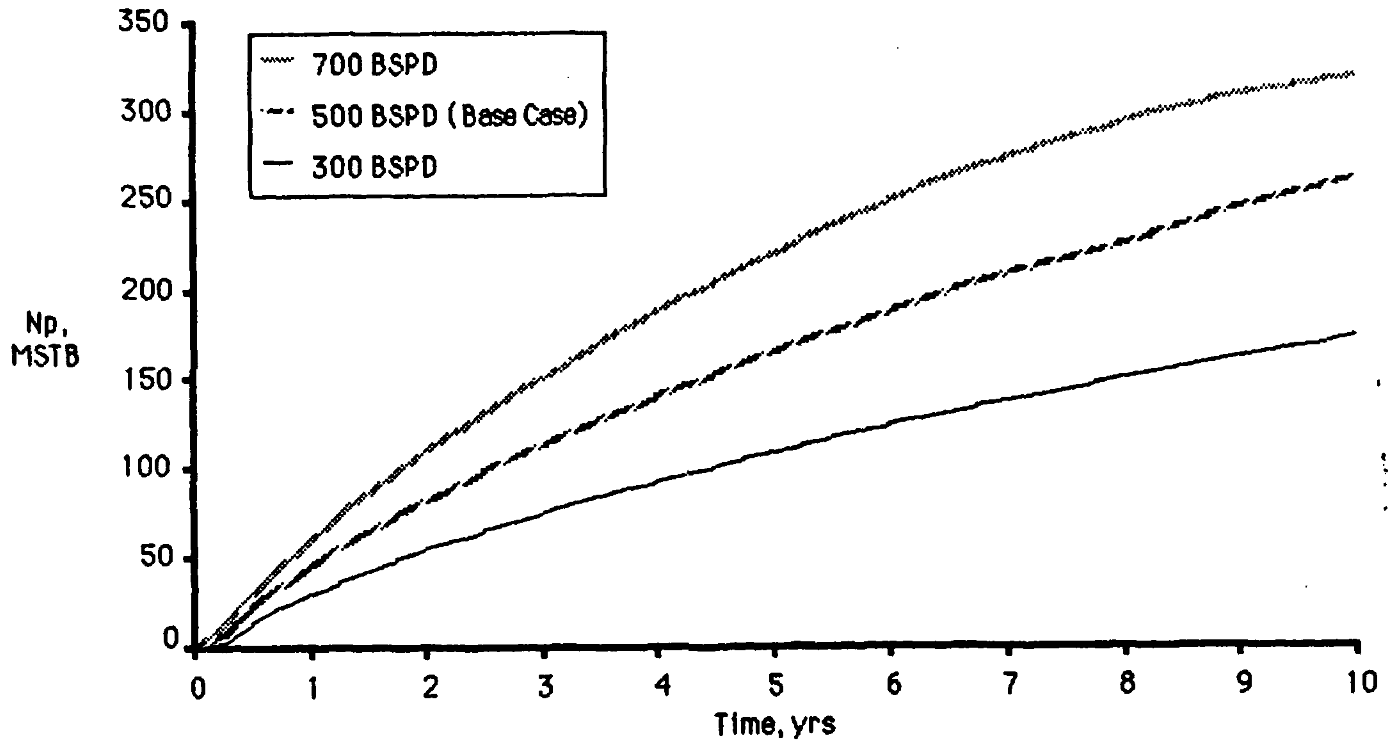

Fig. 6.20. Effect of Injection Rate on Steam Flood

prediction considers a steam overlay, it does not take into account the "steam blanket" effect to the extent as suggested by Vogel (1984). Vogel shows how this effect can lead to an optimum injection rate, above which additional steam injected essentially results only in additional steam being produced.

6.5.2 Effect of Surface Steam Quality

Rather than having an estimated injected steam quality as an input variable, Arima's model offers the benefit of accepting surface steam quality, and then calculating wellbore heat losses to yield the injected steam quality at the sandface. Figure 6.21 illustrates the effect of this parameter on predicted performance. These results are important in that little change is predicted when raising surface steam quality from 80% to 90%, yet a drop in quality from 80% to 70% significantly decreases performance. These results imply that insulation on injection lines is necessary, but that there may be a limit to the benefit of insulation.

6.6 Comparison of EOR Processes

Figures 6.22 and 6.23 summarize the results of this study for 10-acre and 2.5-acre base cases, respectively. In both situations polymer flooding was predicted to give the highest early recoveries, while steamflooding was predicted to yield the highest ultimate recoveries. The larger ultimate recovery for the steamflood was most significant in the comparison of the 2.5-acre base cases. Predicted ultimate recoveries agree well with theory. Polymer flooding can only produce mobile oil, while steam flooding greatly reduces residual oil, enabling more oil to be produced. Steam

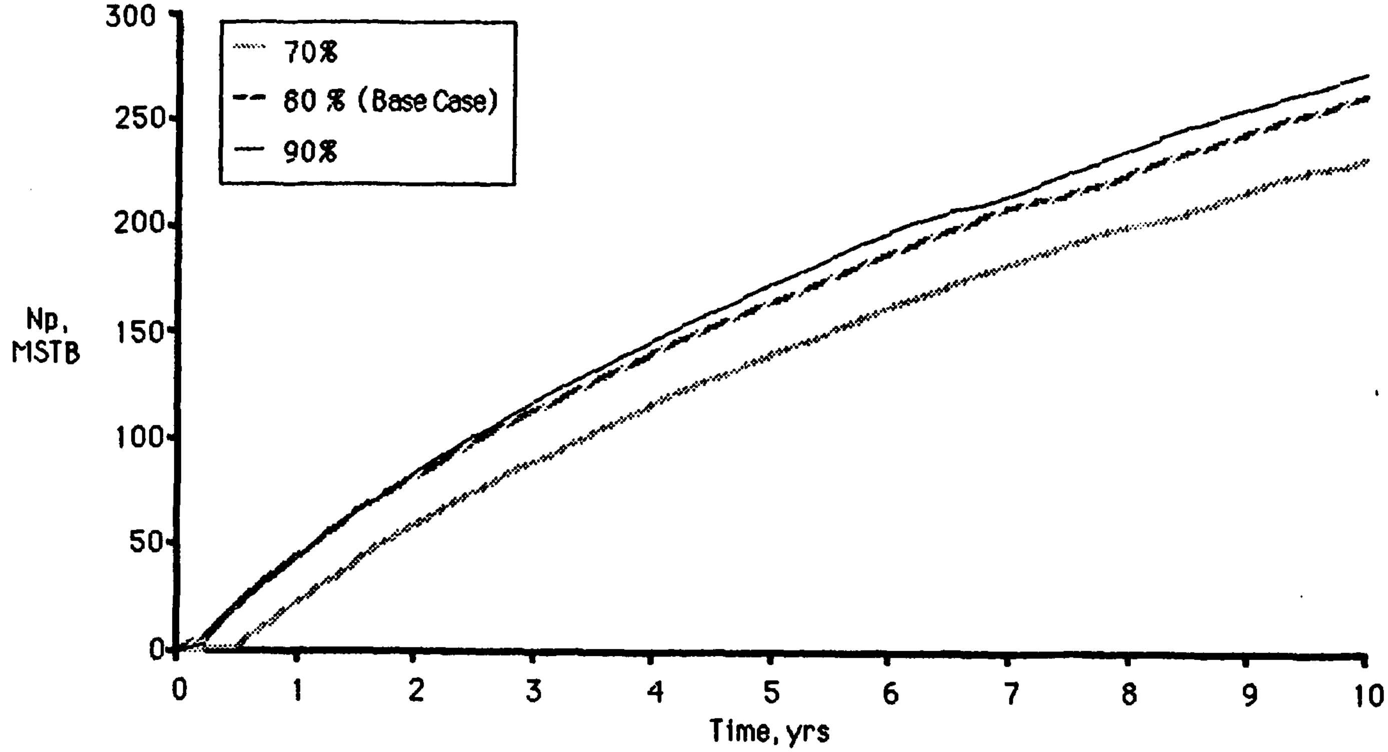

Fig. 6.21. Effect of Steam Quality on Steam Flood

and miscible gas drive mechanisms in an in-situ combustion process can reduce residual oil. However, ultimate recovery would not be as large as for a steamflood since some amount of oil is used as fuel in the reservoir.

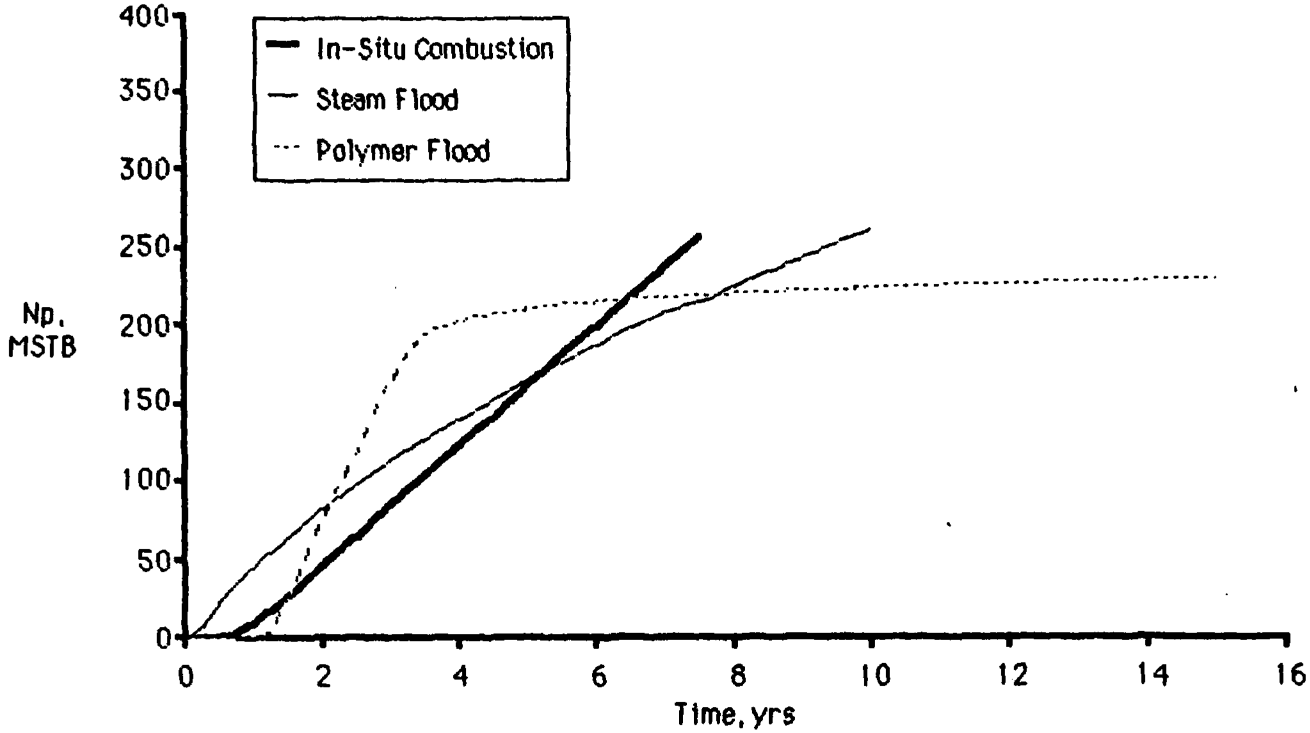

Fig. 6.22. 10-Acre Pattern Production Comparison

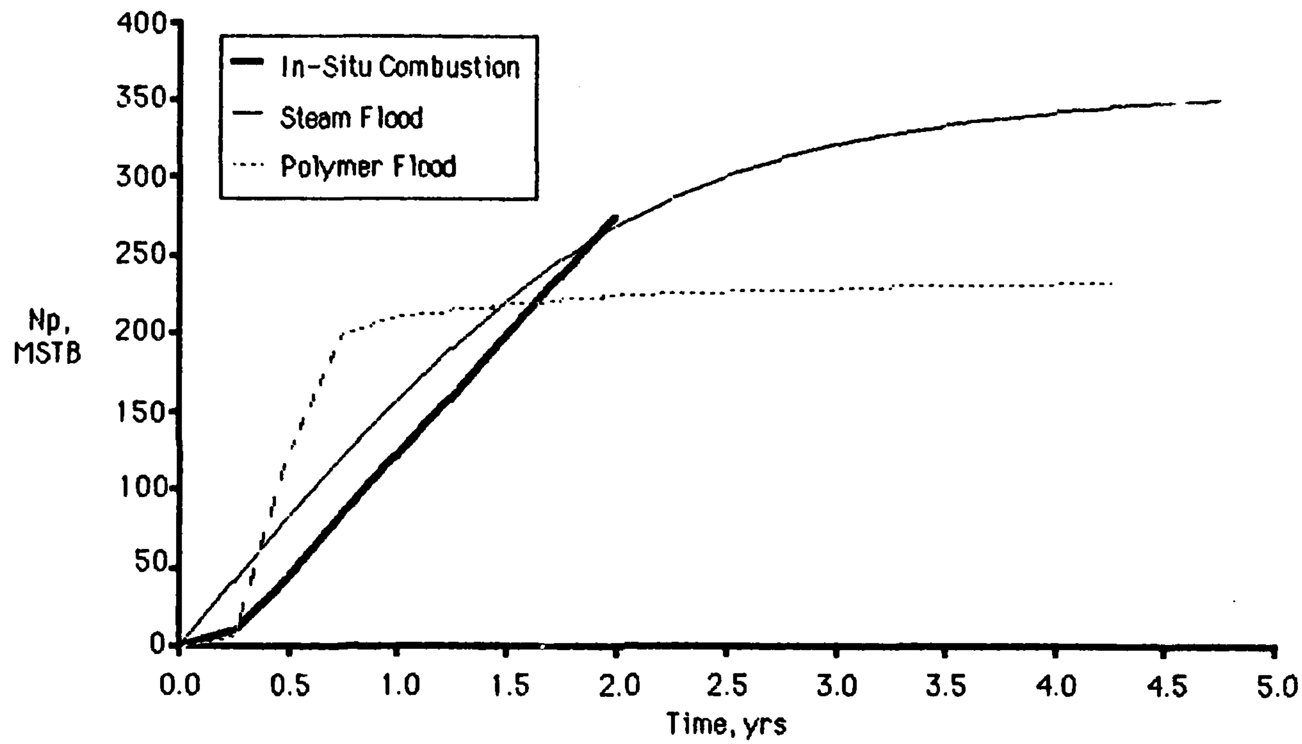

Fig. 6.23. 2.5 Acre Pattern Production Comparison

7. ECONOMIC ANALYSES

Ultimately, the decision to implement EOR operations for the Shannon formation will be based upon economics. Projected revenues must be weighed against anticipated capital and operating costs to determine which process will be most profitable. In this chapter, the set of preliminary production predictions given in the previous chapter were analyzed for profitability. This evaluation was based on assumptions pertaining to oil prices, capital costs, operating costs, and other economic conditions.

As with the many physical variables which must be considered when production predictions are made, there are numerous economic parameters which affect the profitability of a project. In this preliminary analysis, all cost components were not known, and accurate costs for known components were not generally available. However, major capital and operating costs were identified and reasonable estimates made, based upon known process requirements and certain pilot test results. Therefore, just as the production predictions reflected the anticipated character and order of magnitude of performance, economic analyses provide an estimate of profitability. In addition to these preliminary estimates, a template for more detailed future study was established.

7.1 Economic Decision Criteria

As noted earlier, operations at NPR's are unique in the sense that DOE pays no taxes or royalties on production. Net profit and net cash flow are

synonymous and profitability is measured simply in terms of the difference between gross revenues and actual expenses. However, even the U.S. Government must account for the time value of its money, hence the issuance of Treasury bills (T-bills). For this reason, two discounted cash flow decision criteria, Net Present Value (NPV) and Present Value Ratio (PVR), were chosen to compare the profitability of the EOR processes evaluated.

7.1.1 Time Value of Money

Since the value of money changes with time, it is necessary to account for this change in any economic decision. The time value of money can be described by the compound interest formula [Berlinger (1984)] as:

$$FV = PV(1+i)^n \qquad 7.1$$

where,

FV = Future value of a cash flow

PV = Present value of that cash flow

i = Nominal interest, or discount rate per period

n = Number of periods considered

Simply, this formula shows that a dollar recieved one year from now is not worth as much as one received today due to the loss of a year's investment opportunity. This "opportunity cost" is expressed in terms of the interest, or discount rate at which the money could have appreciated.

An endeavor such as the EOR processes studied herein will result in a series of future cash flows. Equation 7.1 may be manipulated to express the present value of a future cash flow as a function of time and the discount

rate. The sum of these cash flows are termed the Net Present Value. This is expressed as:

$$NPV = \sum_{j=0}^{n}[FV_j/(1+i)^j] \quad \text{.......... 7.2}$$

where j represents the time period in which a cash flow occurs. NPV reflects the total net cash flow for a project, discounted to the common basis of present year dollars. A disadvantage of using NPV as an economic decision tool is that it does not reflect the magnitude of the initial investment required. Thus, two projects may have nearly equal NPV's, but one may have required a much larger initial investment than did the other. Therefore, PVR was included in this study as an additional criterion with which to measure profitability. Berlinger states that the PVR yields the discounted value per dollar of investment. It is expressed as follows:

$$PVR = (NPV - CI)/CI \quad \text{.......... 7.3}$$

where,

PVR = Present value ratio

CI = Capital Investment reqired

7.1.2 Discount Rate

As can be seen from Eq. 7.1, the cost of capital as expressed in the discount rate is an important parameter to profitability. It is, however, affected by inflation, as positive inflation effectively reduces the true discount rate. This was shown by van Rensburg (1984) as:

$$R = (1+i)/(1+I) - 1 \quad \text{.......... 7.4}$$

vhere,

R = True discount rate

i = Nominal discount rate

I = Average inflation rate

n all evaluations of this study the true discount rate was used. The nominal liscount rate was chosen to be the average annual T-bill rate, as this reflects he cost of capital for the operator of NPR-3, the U.S. Government.

'.1.3 Inflation and Escalation

Inflation must necessarily be considered for its effect on future :osts and revenues. Additionally, escalation may be a factor and was :onsidered where appropriate in this investigation. Escalation is the lifference between the rise in a cost or revenue and the general rate of nflation. For example, oil prices in the 1970's rose in price at rates higher han inflation, i.e. they experienced positive escalation. Conversely, drops in)il prices are an example of negative escalation. Future costs and revenues vere thus calculated from initial values, termed "Year 0" values, as follows:

$$Cost_n = Cost_0(1 + I + E)^n \qquad 7.5$$

vhere,

$Cost_n$ = Cost(or revenue) in future year, n

$Cost_0$ = Cost(or revenue) in Year 0

n = Number of years since Year 0

I = Average annual inflation rate, fraction

E = Average annual escalation, fraction

2 Methodology

For each process, NPV and PVR were found and various economic nsitivity analyses performed using a microcomputer spreadsheet model as itlined in Appendix 10.2. Sensitivities to the physical and operational irameters found to be significant in Chapter 6 were also investigated. For ich process, a chart is presented which depicts base case NPV and CI for ith the 10-acre pattern and for four 2.5-acre patterns. Results for physical id operational variables identified in Chapter 6 are then shown. Finally, sults of the analyses of all three processes with regard to economic irameters are given.

In all evaluations the convention given by van Rensburg, of msidering cash flows as if they occurred at year end, was used. Capital osts were considered to occur in Year 0 and inflation, escalation, and minal discount rates were assumed to be constant average values. The isic unit of evaluation was taken to be a 10-acre 5-spot well pattern. This ould require the drilling of one injection well and workover and stimulation the equivalent of one existing production well. Additionally, a 2.5-acre ise case was evaluated. As can be seen from Fig. 6.1, this arrangement would quire four injection wells and the equivalent of three producing wells to be illed per 10-acre unit. Workover and stimulation of the equivalent of one ell per 10-acre unit would also be required for the development of four 5-acre well patterns. Economy of scale for a potential field-wide expansion as assumed making application of fractional costs appropriate. For

nple, a polymer mixing unit which would serve ten 10-acre patterns may $100,000 and be operated by one man receiving $30,000 per year in pay benefits. The per pattern capital cost would thus be $10,000 while the ıal per pattern labor cost would be $3,000 (not adjusted for inflation and ılation).

Table 7.1 Economic Base Case Assumptions	
T-Bill Rate	10%
Inflation Rate	4%
Initial Oil Price	$29/bbl
Oil Price Escalation	-4%
Initial Natural Gas Price	$3/MCF
Initial Polymer Price	$2/lb
Initial Electricity Price	4¢/KWH
Gas, Polymer and Electricity Escalation	0%

Economic Base Case

To compare the profitability of in-situ combustion, polymer ıding, and steamflooding in the Shannon reservoir at NPR-3, an economic e case was established. Table 7.1 lists base case assumptions for discount ', inflation rate, Year 0 prices and escalation factors. Note that at the ımed 4% inflation rate, the true discount rate was calculated to be 5.77%. ɔ, oil prices in the base case studies were held at a constant $29/bbl due he -4% oil price escalation. Natural gas, which would be used as a fuel for ım generation, is produced and processed at NPR-3. Although this gas is marketed, it was assumed that it could be sold for $3/MCF. This was

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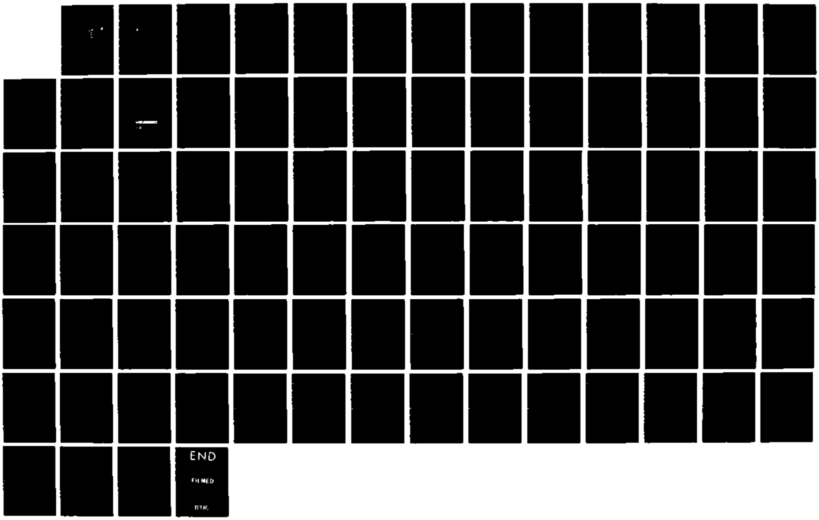

MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

taken to be the true cost of gas. A current electricity price is reflected in the \$.04/KWH [Schulte (1984)], and polymer prices were assumed to be \$2.00/lb. Other specific costs are discussed in the following sections where appropriate. Appendix 10.2 contains spreadsheets for economic base cases, as well as a discussion of formulas used.

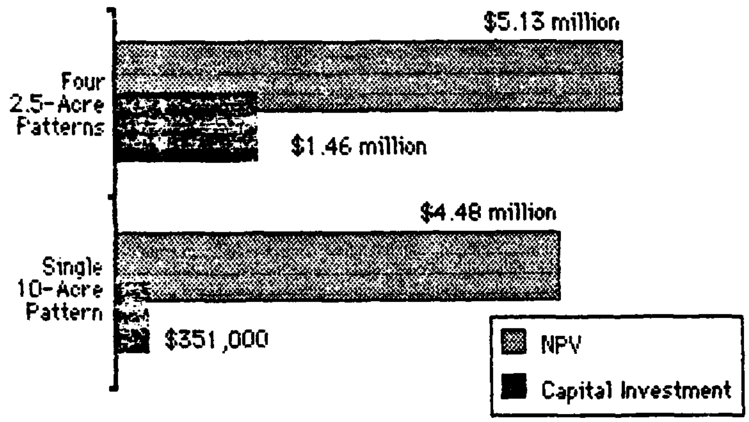

Fig. 7.1. Projected Net Present Value and Capital Investments estimated for in-situ combustion in the Shannon formation.

7.4 In-Situ Combustion

The production history for in-situ combustion which was given in Fig. 6.2 was evaluated economically, and showed a NPV of \$4.48 million for its approximately 8-year life. Figure 7.1 shows that economics were judged to be more favorable for the 2.5-acre base case with this scenario, yielding a NPV of \$5.13 million, but with a CI of \$1.46 million. Major costs would be capital and operating costs for air compression, and the cost of pre-heating the reservoir in order to sustain combustion. Air compressor electricity

requirements were estimated from a correlation given by White and Moss (1983).

In considering economic results for the in-situ combustion base case, it must be noted that the binary screening of Chapter 5 listed the process as having only marginal potential. Also, predictions were made with an untested model that predicted a high, consistent production rate for a considerable amount of time showing no decline, but terminating production abruptly, as discussed in Chapter 6.

7.4.1 Effect of Air Injection Rate

Figure 7.2 shows the increase in profitability predicted for increased air injection rates. Note that NPV is significantly lower for 500 MCFD than for the 850 MCFD base case, a difference of approximately $2 million. However, an equal rise in injection rate above 850 MCFD to 1200 MCFD caused predicted NPV to rise only slightly. The implication for actual operation is that a high air injeciton rate is desirable, but that an economic optimum exists. Injectivity would also be a limiting factor.

7.4.2 Effect of Oxygen-Enriched Air Injection

Figure 7.3 shows the potential economic benefits to oxygen-enriched air injection. The 30% oxygen and 50% oxygen cases yield NPV's of $4.8 million and $5.2 million, respectively. While higher capital and operating costs are required for oxygen production, air compression costs are reduced for equivalent amounts of oxygen injected. Further, capital and operating

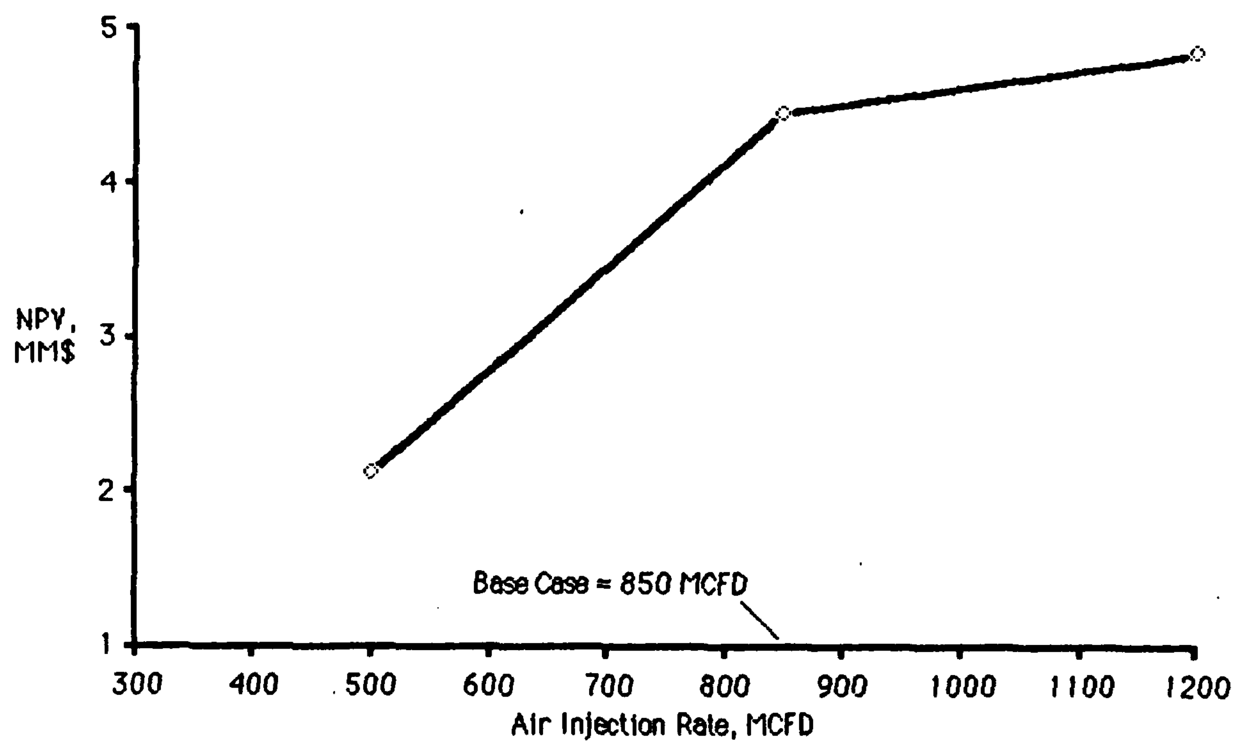

Fig. 7.2. In-Situ Combustion Sensitivity to Air Injection Rate

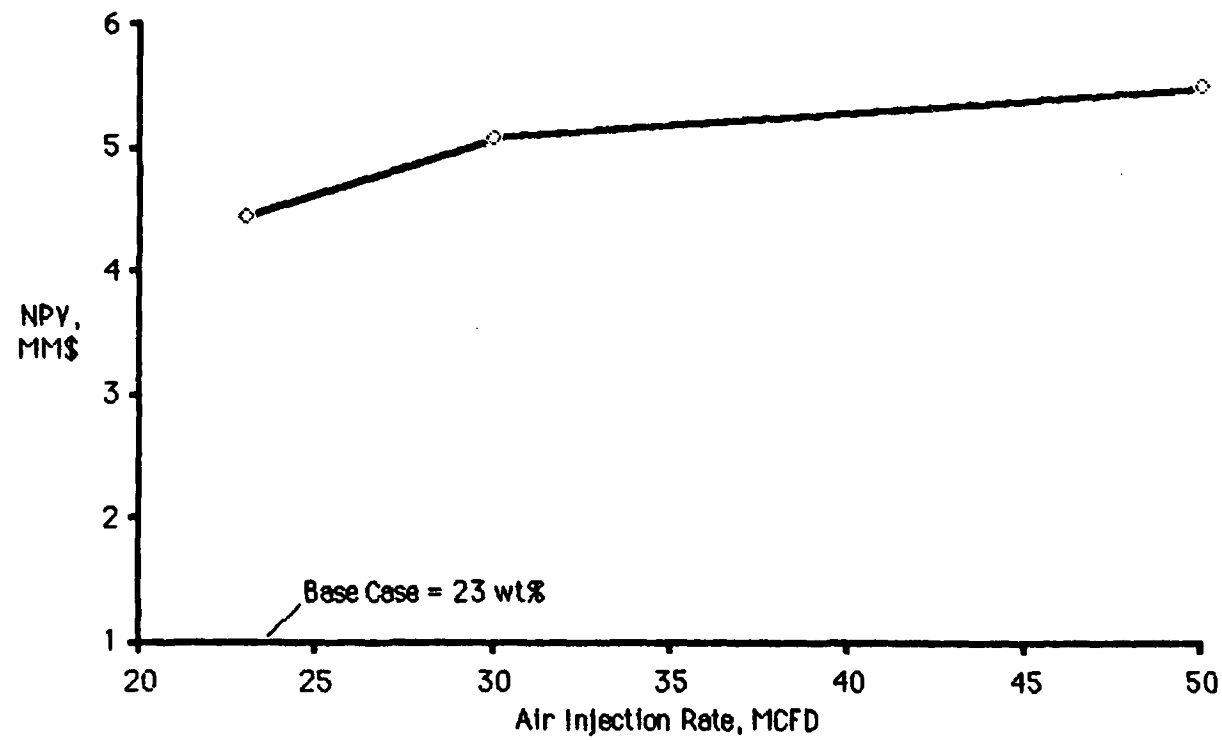

Figure 7.3. In-Situ Combustion Sensitivity to Oxygen-Enriched Air

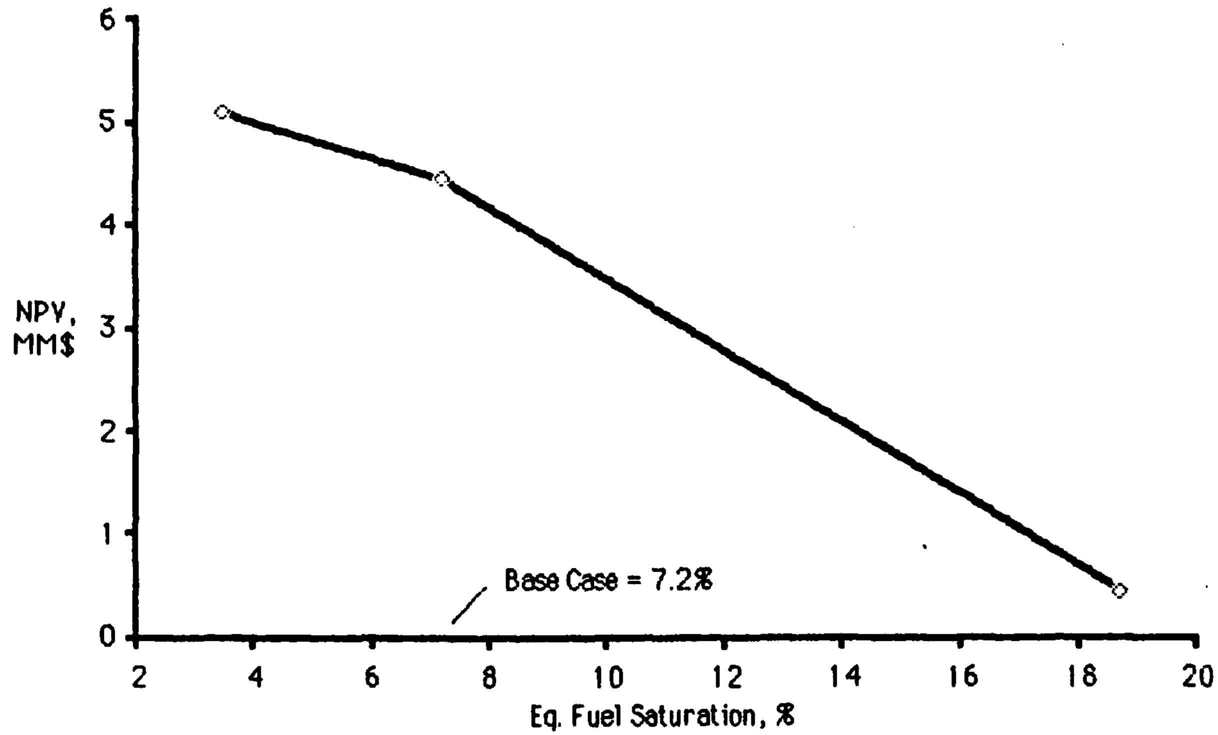

Figure 7.4. In-Situ Combustion Sensitivity to Eq. Fuel Saturation

costs have shown to be virtually the same at NPR-3 for the injection of oxygen-enriched air in any concentration [Zargarnian (1984)]. Therefore, this evaluation points out that oxygen-enriched air should have significant economic advantages for application to the Shannon formation.

7.4.3 Effect of Equivalent Fuel Saturation

Figure 7.4 illustrates the effect which equivalent fuel saturation was predicted to have on profitability. The approximately $4 million difference in NPV between S_{OF} = 7.2% and S_{OF} = 18.7 % shows that the definition of this property will be necessary before full-scale operations should be considered.

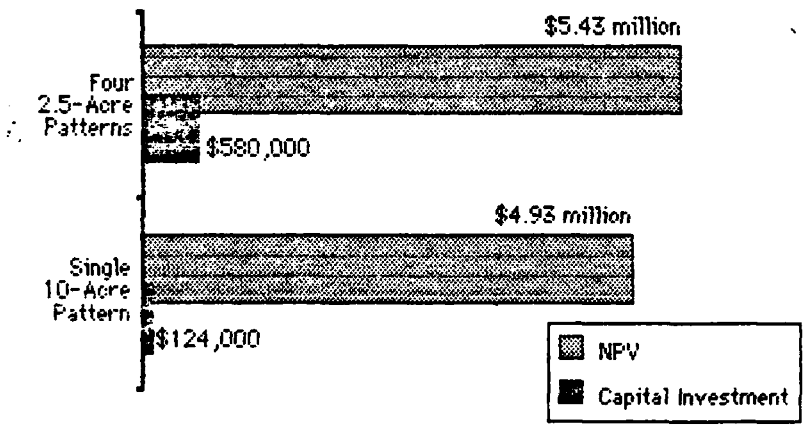

Fig. 7.5. Projected Net Present Value and capital investments for a polymer flood in the Shannon formation.

7.5 Polymer Flooding

Polymer flooding was found to have the best economic results of the three processes investigated, as shown in Fig. 7.5. Predicted benefits of this

process were low capital and operating costs as well as high early production. This better economic performance is in spite of the lower predicted ultimate recovery for polymer flooding compared with in-situ combustion and steamflooding. Figure 7.5 also shows that 2.5-acre spacing would produce better results than would 10-acre spacing.

7.5.1 Effect of Polymer Concentration

Results of the sensitivity analysis of injected polymer concentration are shown on Fig. 7.6. Predictions give little change for the three cases, with the lower 250 ppm concentration showing the better results. Apparently, this is due to the lower viscosity of injected fluid, and possibly an insufficient consideration for adverse mobility ratio problems in the application of Jones's predictive model.

7.5.2 Effect of Polymer Slug Size

As with polymer concentration, better economics are predicted for lower total polymer injection, as the 0.25 PV slug was predicted to provide the best profitability. In each of the three cases considered, polymer concentration was held constant at 700 ppm. As shown on Fig. 7.7, the minimum NPV was calculated for a 0.5 PV slug.

7.5.3 Effect of Oil Viscosity

The need for adequate definition of oil viscosity and its apparent areal variation in the Shannon formation is implied by Fig. 7.8. This plot shows that NPV is predicted to be $1 million higher for 7 cp oil than for 20 cp

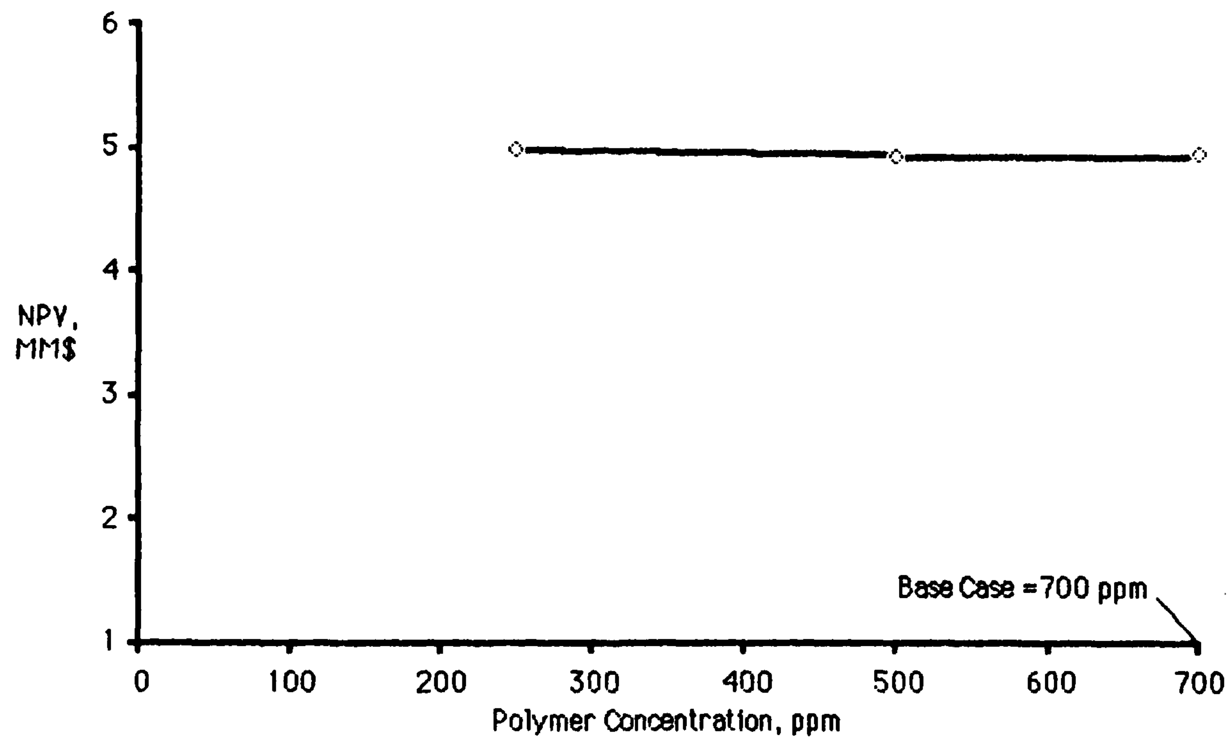

Fig. 7.6. Polymer Flood Sensitivity to Concentration

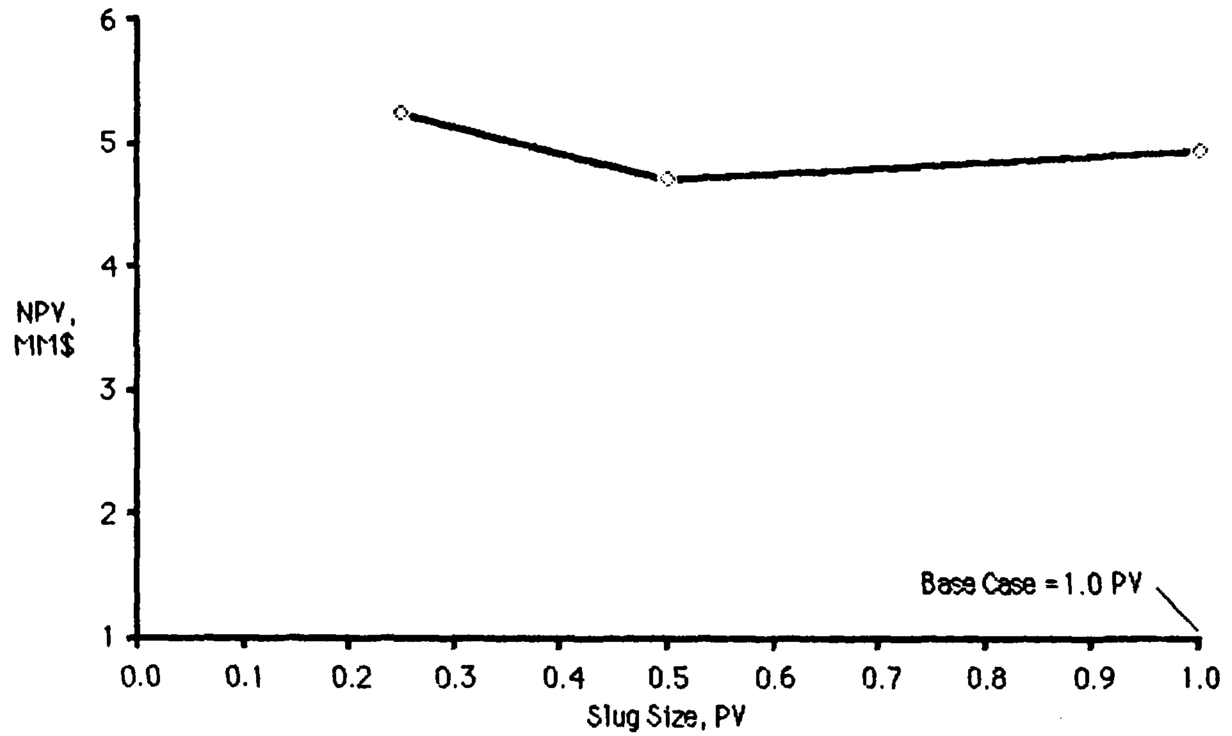

Figure 7.7. Polymer Flood Sensitivity to Slug Size

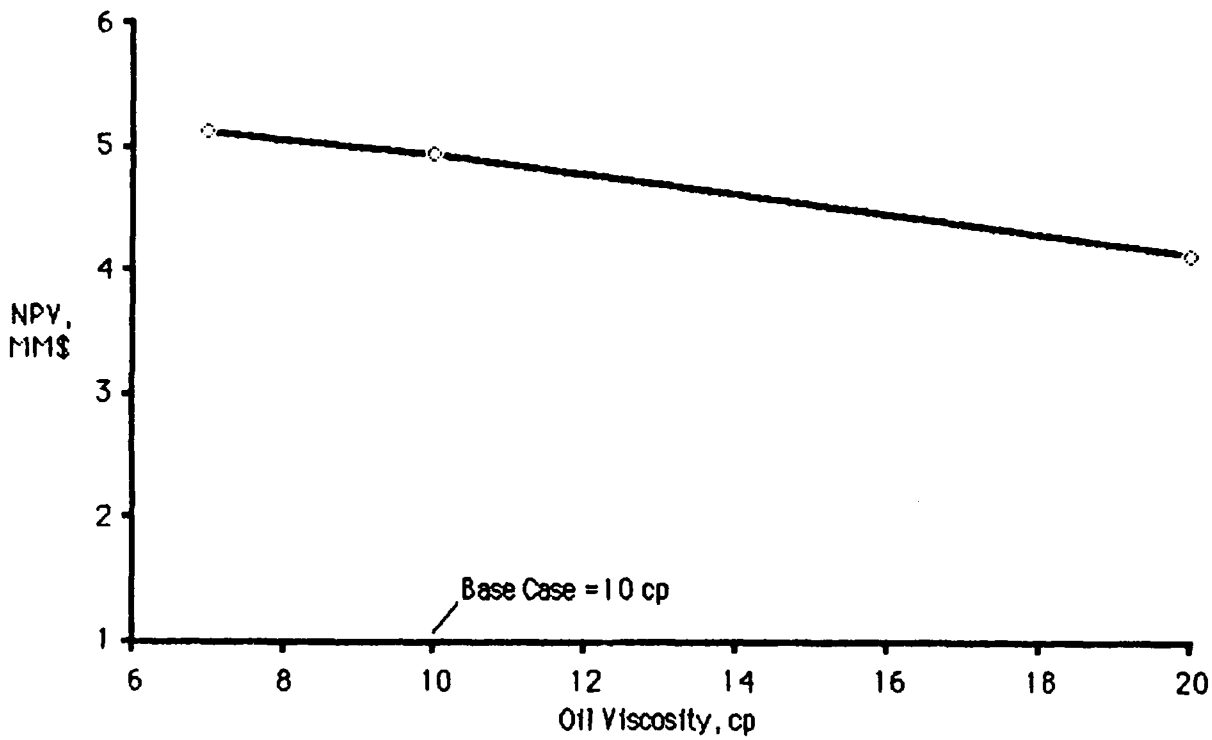

Fig. 7.8. Polymer Flood Sensitivity to Oil Viscosity

oil. A more complete knowledge of reservoir oil viscosity would not only provide more accurate predictions, but it would also be a consideration in selection of reservoir zones when implementing polymer flooding.

7.6 Steamflooding

Figure 7.9 shows predicted economic results for steamflooding in the Shannon reservoir. Specific cost items considered are listed in Appendix B, the largest of which are for steam generation and water treatment. Cost estimates for steamflooding are probably the more realistic of the three cases considered, as more data were available. Figure 7.9 also illustrates that four 2.5-acre well patterns were predicted to give a larger NPV than did the single 10-acre pattern.

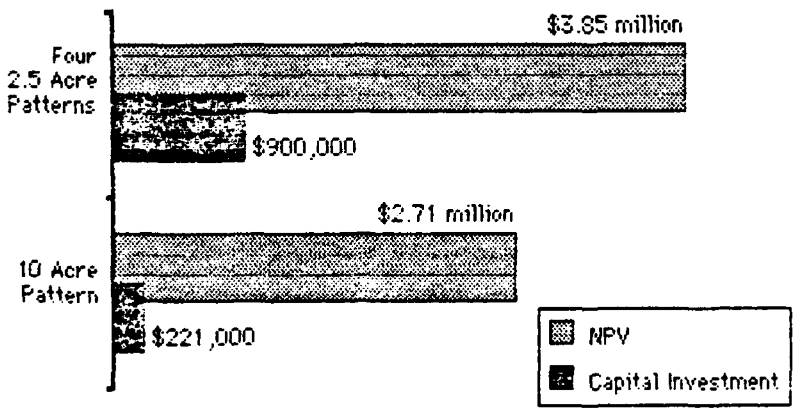

Fig. 7.9. Projected Net Present Value and required capital investments for steamflooding base cases.

7.6.1 Effect of Steam Injection Rate

Figure 7.10 shows that as injection rates are raised, profitability is predicted to increase for steamflooding. The projected increase in NPV is large between 300 and 500 BSPD, while the difference between injecting 500

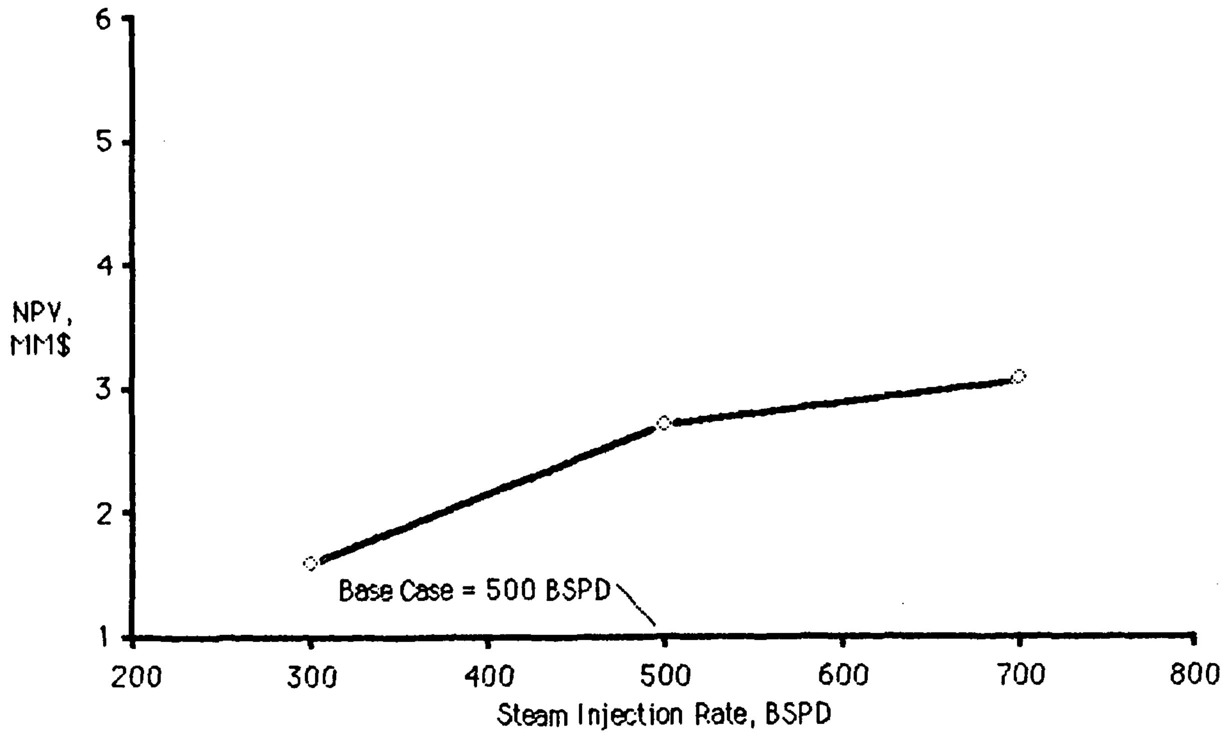

Fig. 7.10. Steamflood Sensitivity to Steam Injection Rate

MM$	Million dollars
n	Number of periods considered in cash flow analysis
N_p	Cumulative oil production, MSTB
NPR-3	Naval Petroleum Reserve No. 3
NPV	Net Present Value, $
OOIP	Original oil in place
ppm Ca/Mg	Concentration of calcium and magnesium ions, ppm
PV	Pore volumes, fraction
PV	Present value of a cash flow, $
PVR	Present value ratio, unitless
Q_o	Oil production rate, BOPD
R	True discount rate, %
S_o	Oil saturation, %
S_{OF}	Equivalent fuel saturation, %
S_{ors}	Saturation of oil left as residual oil to steam, %
STB	Stock tank barrel
S_w	Water saturation, %
TDS	Total dissolved solids, ppm
V_{DP}	Dykstra-Parsons permeability variation, unitless
WOR	Water/oil ratio, STB/STB
λ_o	Mobility of oil, md/cp
λ_w	Mobility of water, md/cp
μ_o	Viscosity of oil, cp

9. NOMENCLATURE

Symbol	Description
BHP	Brake horsepower, hp
BOPD	Barrels of oil per day
BSPD	Barrels of cold water equivalent to steam per day
CI	Capital investment, $
$Cost_n$	Cost (or revenue) in future year n, $
$Cost_0$	Cost (or revenue) in Year 0, $
E	Average annual escalation in price, %
EOR	Enhanced oil recovery
FV	Future value of a cash flow, $
i	Nominal discount rate, %
I	Average annual inflation rate, %
k_o	Permeability to oil, md
k_w	Permeability to water, md
M	Mobility ratio, unitless
Mbbl	Thousands of barrels
MCFD	Thousands of cubic feet per day
m_E	Mass of combustion tube material burned, lb_m/ft^3
MMbbl	Millions of barrels
m_R	Mass of reservoir fuel burned, lb_m/ft^3
MSTB	Thousands of stock tank barrels

Limitations of this study concerned the predictive models used, the unknown character of the reservoir, and a lack of complete economic data. The investigation was also limited in scope in that it considered only three EOR processes. As was noted, two other processes, surfactant/polymer flooding and horizontal drilling, merit further investigation. To provide for a more complete treatment, the following recommendations should be acted upon:

- The reservoir should be characterized regarding flow behavior
- Critical variables identified in this study should be accurately defined
- Permeability variation should be determined, and consideration for this parameter should be given to future predictions
- More complete cost requirements and data should be gathered
- Risk analysis, weighing chances and outcomes of success and failure, should be performed
- Other well patterns and well spacings should be evaluated, taking into account the nature of the Shannon reservoir

Estimates of production and economics are offered, but the true value of this work is that it provides a foundation for future study. Past work has been reviewed, the reservoir qualitatively described, potential processes identified, and predictions made for three processes. In the near future, physical and economic data will be improved, and predictions refined. But the results given offer an estimate of the relative effects of various parameters, and the methodology employed has established a framework upon which to base future decisions.

Polymer flooding was shown to have the advantage of low capital investment and high early production, and small pattern size was shown to be advantageous for profitability. Analyses indicated that slug size and polymer concentration were not critical parameters. However, it is felt that a high polymer concentration would be required due to poor past waterflooding performance in the reservoir. It was also shown that performance would be hindered in areas where oil viscosity was as high as 20 cp.

In-situ combustion showed good potential based upon the predictive model employed. However, no consideration for permeability variation was made. Additionally, the production decline which was predicted was determined to be of questionable accuracy. Sensitivity analyses showed that both high air injection rates and high oxygen concentrations would be beneficial. Also, a critical variable, equivalent fuel saturation, was identified as requiring further study. Application in small well patterns was found to be unprofitable due to high capital and operating costs.

Predictions for steamflooding performance indicated that this process has potential to be profitable in the Shannon formation. Small well spacings were also projected to be advantageous. It was shown that steamflooding economics would be sensitive to fuel prices, steam injection rate, and surface steam quality. This analysis suggested that optimum operating conditions would require high steam injection rates, and that substantial capital investments in insulation and efficient steam generation equipment would be profitable.

8. CONCLUSIONS AND RECOMMENDATIONS

Important decisions lay ahead with regard to improving the economic recovery of oil from the Shannon formation at NPR-3. The Shannon reservoir represents a significant resource, estimated to contain over 170 million barrels of oil which are unrecoverable by primary means. Before implementing any EOR scheme, reservoir flow behavior and physical properties must be defined, alternative processes identified, and pilot testing completed and analyzed. Results of these analyses must then be used to judge the potential profitability of the alternatives. A decision should then be made and acted upon regarding which EOR process and what optimum operating parameters should be implemented.

This study has offered a set of preliminary production predictions for application of in-situ combustion, polymer flooding, and steamflooding in the Shannon formation. Included was an analysis of the effect of variability in certain physical and operational parameters. Based upon the evaluation of the effects of these parameters, suggestions for optimum operating conditions were made. A screening of potential EOR processes was also reported in order to identify any other potentially applicable EOR technology. Finally, an economic analysis was performed which showed that polymer flooding exhibited the greatest potential for profitability, followed by in-situ combustion and steamflooding. The economic analyses also showed the relative effects of several economic and physical variables upon profitability.

escalation that could be expected would be 2% above inflation, therefore the NPV profile shows values calculated at 4% inflation for -4%, 0%, and 2% escalation. For reference, Year 5 oil prices for these three scenarios would be $29/bbl, $35.28/bbl, and $38.81/bbl.

7.7.4 Effect of Fuel/Materials Price Escalation

Sensitivity analysis of fuel (natural gas and electricity) and raw materials (polymer) prices is given in Fig. 7.17. Escalation was varied from -4% to 4% at a constant average inflation rate of 4%. As can be seen from the NPV profiles, neither polymer flooding nor in-situ combustion showed a significant change in profitability across the range of values considered. Conversely, steamflooding was shown to be markedly affected by escalation in natural gas prices. It is significant to note not only the "worst case" of 4% escalation in natural gas but the -4% escalation as well. Under the assumptions of this model, -4% natural gas price escalation simply means that natural gas would stay at $3/MCF throughout project life.

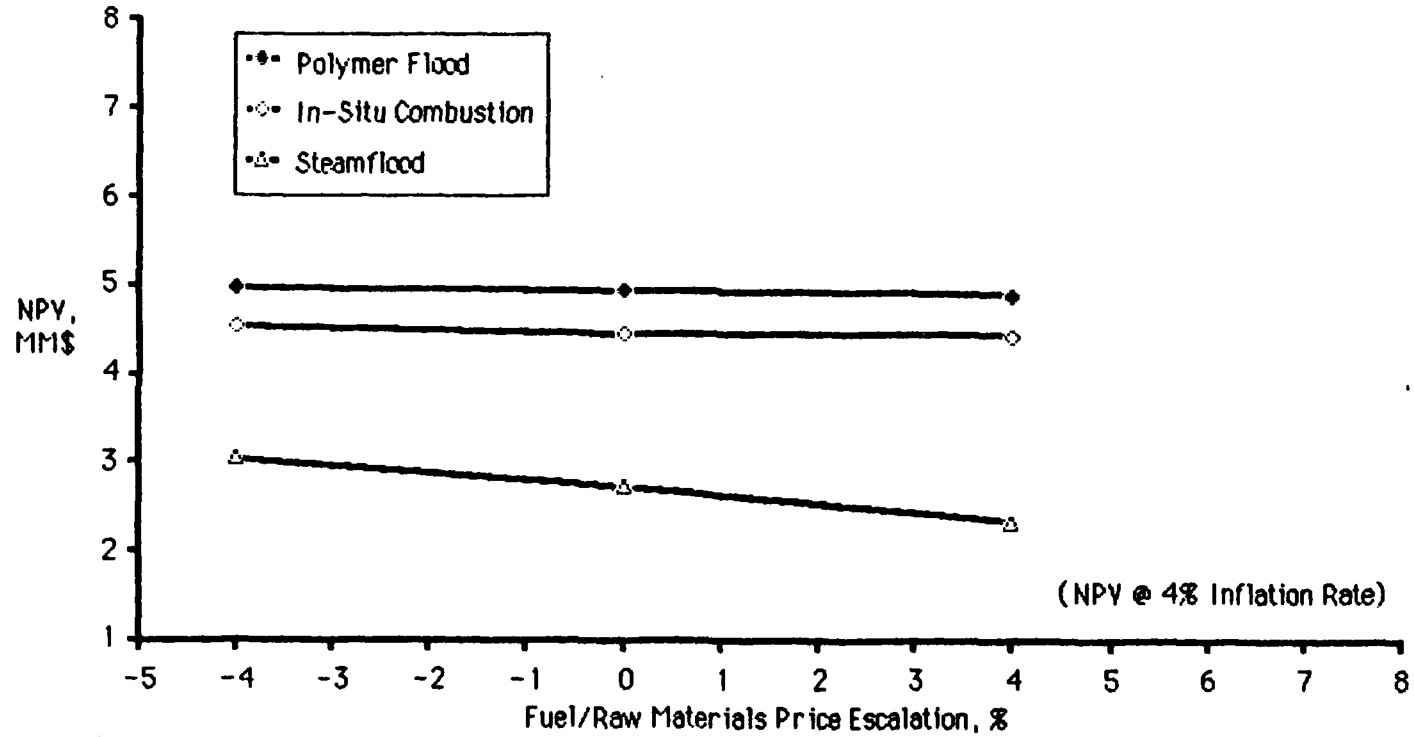

Fig. 7.17. Sensitivity to Fuel/Raw Materials Price Escalation

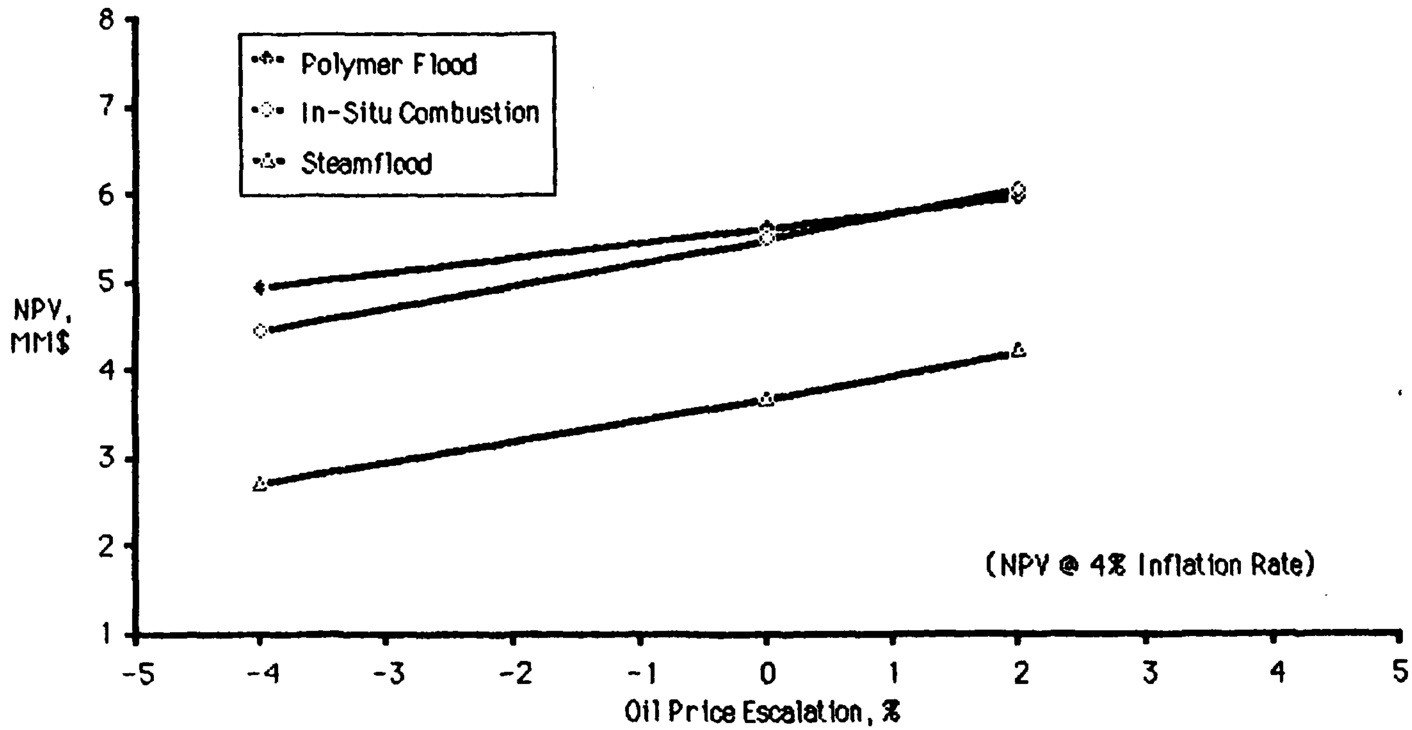

Fig. 7.16. Sensitivity of EOR processes to Oil Price Escalation

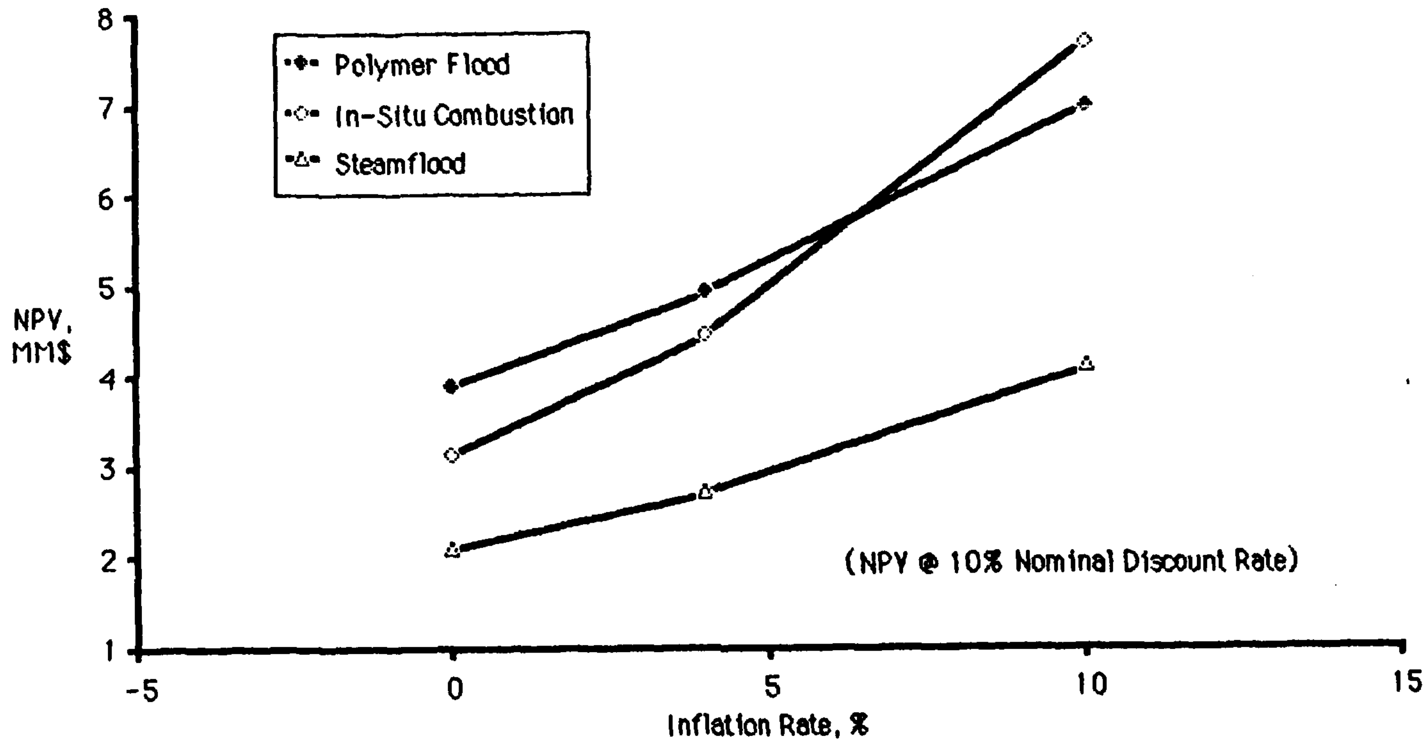

Fig. 7.15. Sensitivity of EOR processes to Inflation Rate

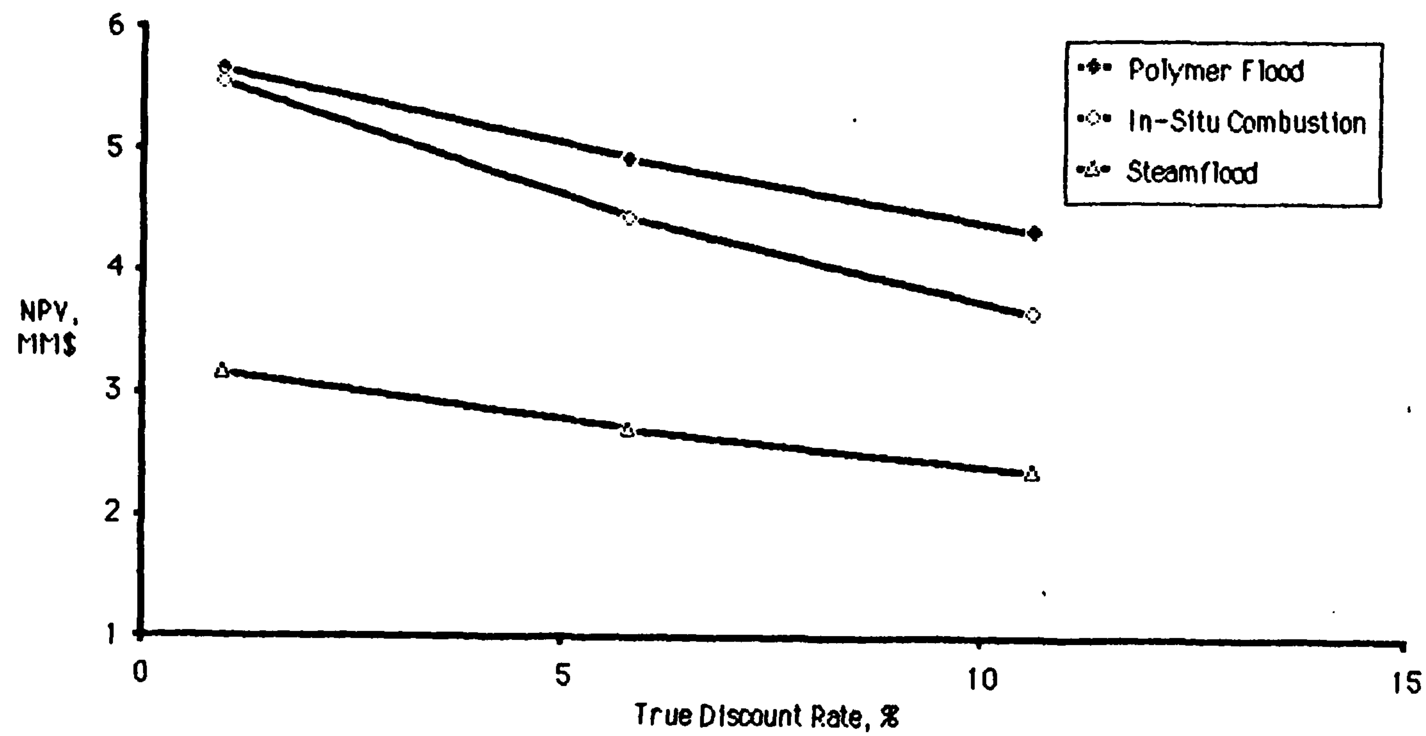

Fig. 7.14. Sensitivity of EOR processes to True Discount Rate

7.7.1 Effect of Discount Rate

The NPV profile measuring the sensitivity of the three EOR processes to true discount rate is given in Fig. 7.14. Note that the three values of true discount rate considered correspond to T-Bill rates of 5%, 10%, and 15% at 4% inflation. All three processes exhibit a decline amounting to a difference of about $1 million in the range considered.

7.7.2 Effect of Inflation

Figure 7.15 is a NPV profile showing projected sensitivity to inflation. This figure indicates that at low inflation rates profitability decreases, and that it increases with higher inflation rates. It is further illustrated that even with the -4% escalation of oil prices assumed for all cases, inflation's effect upon operating costs would be insignificant when compared to rising oil revenues. In-situ combustion was predicted to have an equal NPV as polymer flooding at an inflation rate of approximately 6.5%, and a higher NPV for higher inflation rates. This point reflects the oil price that would be necessary for predicted in-situ combustion performance to overcome its relatively high capital costs in order to match the economic performance of polymer flooding. This corresponds to oil prices rising to $32.81 in Year 5. Additionally, NPV for steamflooding rises with inflation, but at a slower rate than the other processes.

7.7.3 Effect of Oil Price Escalation

Virtually an identical reaction as was observed with inflation is shown in Fig. 7.16 for oil price escalation. It was felt that the highest

raw materials. The analyses presented in the following sections are more important than the actual singular values such reported in Fig. 7.12. It is pointed out by van Rensburg (1984) that these "profiles" provide decision-making tools since so many economic parameters are subject to continual change.

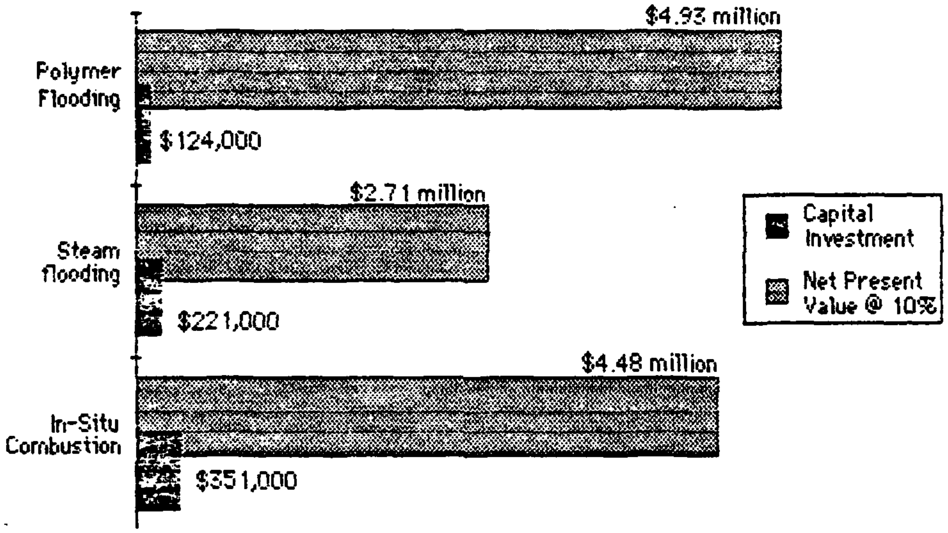

Fig. 7.12 Summary of Net Present Value and capital investment projections for 10-acre base cases.

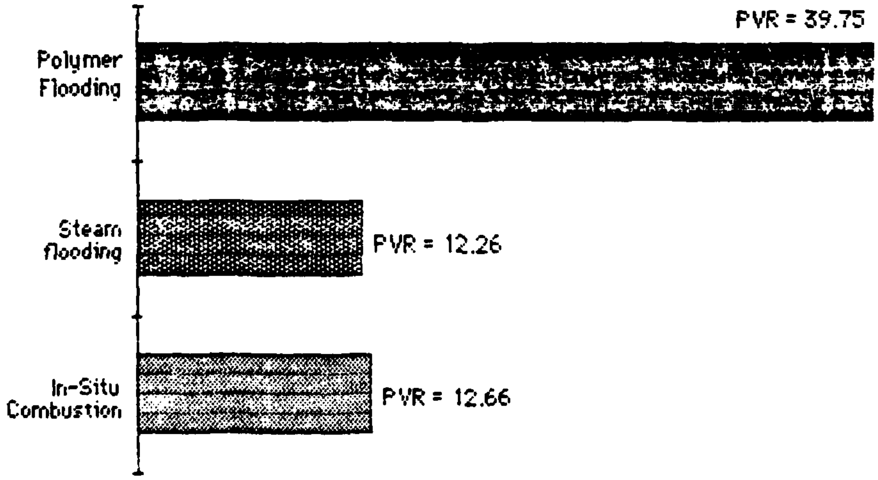

Fig. 7.13 Present Value Ratios projected for the 10-acre base cases.

BSPD and 700 BSPD is not as significant. This analysis suggests that injecting at as high a rate as possible should be optimal. Note that this may conflict with the assertions of Vogel (1984) and Miller (1984) discussed earlier.

7.6.2 Effect of Surface Steam Quality

The economic results given in Fig. 7.11 show that steamquality is an important parameter, predicting that a drop in surface steam quality from 80% to 70% would cause a decline of close to $1 million in NPV for a 10-acre pattern. This suggests that larger capital investments in efficient equipment and insulation would be worthwhile.

7.7 Process Comparison

Figure 7.12 summarizes the results obtained from the economic analyses of the 10-acre base cases. It can be seen that polymer flooding had the highest predicted NPV, followed by in-situ combustion and steamflooding. The PVR, shown in Fig. 7.13, also suggests that polymer flooding would have the best profitability of the processes considered. However, the evaluation of EOR potential was not complete with only an identification of NPV and PVR, evaluating the variables considered thusfar. In addition to the physical parameters which were analyzed for their effect on process performance and profitability, economic uncertainties required sensitivity analysis.

Four economic factors were considered in sensitivity analysis: discount rate, inflation, oil price escalation, and escalation in fuels and/or

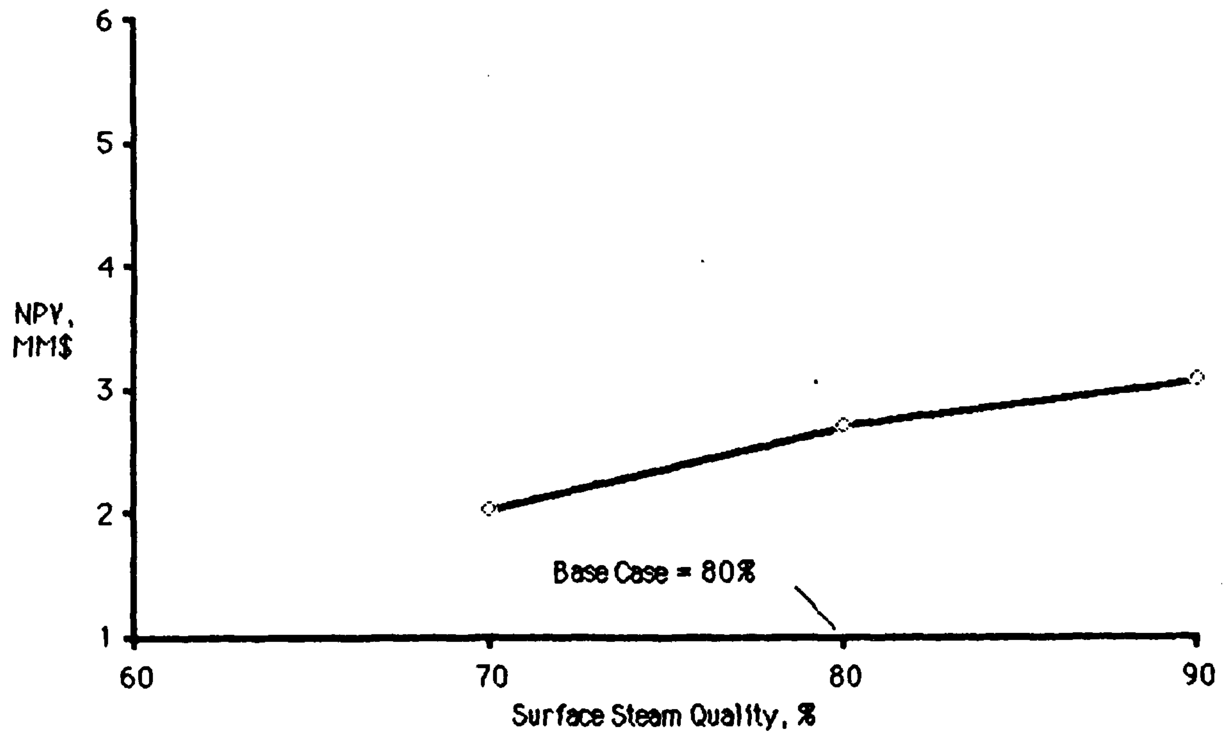

Fig. 7.11. Steamflood Sensitivity to Surface Steam Quality

μ_w	Viscosity of water, cp
ρ_o	Density of oil, lb_m/ft^3
ρ_w	Density of water, lb_m/ft^3
ϕ	Porosity of reservoir, fraction
ϕ_E	Porosity of combustion tube material, fraction

10. APPENDIX

10.1 Predictive Model Input and Output

This appendix is composed of three sections: sample output for the three computer models used in this study are contained in sections 10.1.1 10.1.2, and 10.1.3.

10.1.1 In-Situ Combustion Model Input and Output

Input data requirements and sample output from the in-situ combustion predictive model of Genrich (1984) are given in the following pages. FORTRAN source code exists in seven separate files which must be compiled at one time in order for the program to run. Input data is separated into two files, one containing the required and optional input parameters, and the other giving an injection rate schedule. As can be seen from the listing of input variables, the predictive model will consider very limited or very extensive reservoir data.

```
1

ENTER THE FOLLOWING REQUIRED PARAMETERS

01   RESERVOIR DEPTH                                [FT]
02   RESERVOIR NET PAY                              [FT]
03   POROSITY                                 [FRACTION]
04   ABSOLUTE PERMEABILITY                          [MD]
05   OIL GRAVITY                                   [API]
06   RESERVOIR AREA                               [ACRE]
07   DISTANCE INJECTION TO PRODUCTION WELL          [FT]
09   INPUT ARRAY LENGTH                              [#]

1

THE FOLLOWING OPTIONAL PARAMETERS CAN BE SET
BY ENTERING THE CORRESPONDING NUMBER AND VALUE

00   END OF OPTIONAL PARAMETER INPUT

11   INITIAL RESERVOIR TEMPERATURE                  [ F]
12   BOTTOM HOLE INJECTION TEMPERATURE              [ F]
13   INITIAL RESERVOIR PRESSURE                   [PSIA]
14   BOTTOM HOLE PRESSURE PRODUCING WELL          [PSIA]
15   TOTAL PAY                                      [FT]
16   ROCK DENSITY                              [LBM/CUF]

21   INITIAL OIL SATURATION                   [FRACTION]
22   INITIAL GAS SATURATION                   [FRACTION]
23   INITIAL RESIDUAL WATER SATURATION        [FRACTION]
24   INITIAL RESIDUAL GAS SATURATION          [FRACTION]
26   RESIDUAL FUEL SAT. AFTER COMBUSTION      [FRACTION]
27   EQUIVALENT FUEL SATURATION               [FRACTION]

31   OIL VISCOSITY AT INITIAL TEMPERATURE           [CP]
32   MOL WEIGHT OF FUEL
33   SOLUTION GAS-OIL RATIO                    [SCF/STB]
34   HC-GAS GRAVITY                               [G/CC]
35   HC-GAS MOL WEIGHT
36   HC-GAS CRITICAL TEMPERATURE                    [ R]
37   HC-GAS CRITICAL PRESSURE                     [PSIA]
38   HC-GAS ACENTRIC FACTOR

41   MOL WEIGHT OF UNCONDENSABLE GAS
42   UNCOND. GAS OXYGEN WEIGHT FRACTION
43   UNCOND. GAS OXYGEN MOL FRACTION
44   UNCOND. GAS CRITICAL TEMPERATURE               [ R]
45   UNCOND. GAS CRITICAL PRESSURE                [PSIA]
46   UNCOND. GAS ACENTRIC FACTOR

51   REACTION RATE PRE-EXPONENTIAL CONST. [1/D PSI]
52   ACTIVATION ENERGY                      [BTU/LB MOL]
```

```
53   EXPONENT FOR PARTIAL OXYGEN PRESSURE
54   EXPONENT FOR CONCENTRATION OF OIL
55   HEAT OF COMBUSTION          [BTU/LBM O2 CONSUMED]
56   MOL OF O2 TO BURN 1 MOL OF FUEL
57   MOL OF WATER PER MOL OF FUEL BURNED
58   OXYGEN CONSUMPTION EFFICIENCY           [FRACTION]
59   BURNING EFFICIENCY                      [FRACTION]

1

61   KPWRC AT RESERVOIR TEMPERATURE
62   CHANGE OF KPWRC PER UNIT TEMP.                [1/F]
63   KPGRC AT RESERVOIR TEMPERATURE
64   CHANGE OF KPGRO PER UNIT TEMP.                [1/F]
65   KPOCW AT RESERVOIR TEMPERATURE
66   CHANGE OF KPOCW PER UNIT TEMP.                [1/F]
67   EXPONENT FOR KROW
68   EXPONENT FOR KROG
69   EXPONENT FOR KRW AT RESERVOIR TEMP.
70   CHANGE OF EXPONENT FOR KRW WITH PRESSURE
71   EXPONENT FOR KRG

81   ABSOLUTE PRECISION FOR ITERATIVE CALCULATIONS
82   EXTENDED OUTPUT                             (YES=1.)
83   WELL PATTERN
                          (2-SPOT,ISOLATED    =  2.)
                          (3-SPOT,ISOLATED    =  3.)
                          (5-SPOT,ISOLATED    =  4.)
                          (5-SPOT,DEVELOPED   =  5.)
                          (7-SPOT,ISOLATED    =  6.)
                          (7-SPOT,DEVELOPED   =  7.)
                          (7-SPOT,MODIFIED    =  8.)
                          (9-SPOT,ISOLATED    =  9.)
                          (9-SPOT,MODIFIED    = 10.)
                          (STAGGERED LINE     = 11.)

91   RUN NUMBER                                   [#]

1

ENTER INJECTION RATES OF AIR [SCF/D] AND WATER [STB/D]
TOGETHER WITH CORRESPONDING TIME [DAYS]

TIMESTEP    2:
COMBUSTION ZONE TEMPERATURE SET TO THE CLOSEST LIMITING VALUE
TIMESTEP    3:
COMBUSTION ZONE TEMPERATURE SET TO THE CLOSEST LIMITING VALUE
TIMESTEP    4:
COMBUSTION ZONE TEMPERATURE SET TO THE CLOSEST LIMITING VALUE
```

1

SHANNON FIREFLOOD BASE CASE #1 - 10 ACRE 5-SPOT

```
INPUT  PARAMETER  LIST                                      RUN #     1

RESERVOIR DATA                 :
LENGTH                  660.0  FT   AREA                       10.0 ACRE
DEPTH                   553.0  FT   ROCK DENSITY              124.0LB/CF
NET PAY                  75.0  FT   TOTAL PAY                  97.0   FT
POROSITY                 .190       ABS. PERMEABILITY         200.0   MD
INITIAL PRESSURE         70.0 PSIA  INITIAL TEMPERATURE        65.0    F

INITIAL SATURATIONS            :    OIL                        .450
WATER                    .520       GAS                        .030

RESIDUAL SATURATIONS           :
WATER AT INIT. COND.     .500       GAS AT INIT. COND.            0
EQUIVALENT FUEL          .072       FUEL AFTER COMBUSTN           0

BOTTOM HOLE CONDITIONS         :
INJECTION TEMP.          65.0   F   PRODUCTION PRESSURE        70.0 PSIA

OIL              PROPERTIES :
OIL GRAVITY              32.0  API  SOLUTN GAS-OIL RATIO       32.0CF/BL
INIT. VISCOSITY          10.0  CP   MOL WEIGHT OF FUEL         13.4

HYDROCARBON GAS  PROPERTIES :       GAS GRAVITY                .554
CRIT. TEMPERATURE       343.7   R   CRIT. PRESSURE            677.1 PSIA
MOLECULAR WEIGHT         16.0       ACENTRIC FACTOR            .003

UNCONDENSABLE GAS PROPERTIES :
CRIT. TEMPERATURE       238.4   R   CRIT. PRESSURE            547.0 PSIA
MOLECULAR WEIGHT         29.0       ACENTRIC FACTOR            .035
OXYGEN WEIGHT FRACT.     .231       OXYGEN MOL FRACTION        .242

COMBUSTION       PARAMETERS :
RATIO OF STOICHIOMETRIC NUMBERS     IN REACTION EQUATION
          1.25 MOL O2/MOL FUEL                .73 MOL H2O/MOL FUEL
OXYGEN CONSUMPT. EFF     .800       BURNING EFFICIENCY         1.000
HEAT OF COMBUSTION     5661.4 BTU/LBM O2

REACTION KINETICS PARAMETERS :
PRE-EXP. CONSTANT                                 7432100.3    1/D PSI
ACTIVATION ENERGY                                   32200.0 BTU/LB MOL
EXP. PART. O2 PRESS.     .750       EXP. OIL CONCENTRATN       1.000

REL. PERMEABILITY PARAMETERS :
INIT. VALUE OF KRWRO     .250       CHANGE OF KRWRO            .002  1/F
INIT. VALUE OF KRGRO    1.000       CHANGE OF KRGRO               0  1/F
INIT. VALUE OF KROCW    1.000       CHANGE OF KROCW               0  1/F
EXPONENT FOR KROW       3.000       EXPONENT FOR KROG          2.000
INITIAL EXP. FOR KRW    1.000       CHANGE IN EXP. KRW            0
EXPONENT FOR KRG        2.000

MAX. AREAL SWEEP EFF     .625       ITERATION PRECISION        .1000E-04
```

1

RUN # 1	INJECTION		PRODUCTION			
CUM. TIME [DAYS]	AIR [SCF/DAY]	WATER [STB/DAY]	OIL [STB/DAY]	WATER [STB/DAY]	HC-GAS [SCF/DAY]	AIR [SCF/DAY]
91.30	.8500E+06	0	0	.1892E+03	.1826E+05	.8386E+06
182.60	.8500E+06	0	0	.1375E+03	0	.8396E+06
273.90	.8500E+06	0	.2403E+02	.2034E+03	0	.8458E+06
365.20	.8500E+06	0	.6371E+02	.1672E+03	0	.8436E+06
456.50	.8500E+06	0	.9040E+02	.1533E+03	0	.8436E+06
547.80	.8500E+06	0	.1823E+03	.1410E+03	0	.8434E+06
639.10	.8500E+06	0	.1852E+03	.1409E+03	0	.8436E+06
730.40	.8500E+06	0	.1856E+03	.1403E+03	0	.8434E+06
821.70	.8500E+06	0	.1854E+03	.1404E+03	0	.8435E+06
913.00	.8500E+06	0	.1855E+03	.1404E+03	0	.8435E+06
1004.30	.8500E+06	0	.1855E+03	.1405E+03	0	.8435E+06
1095.60	.8500E+06	0	.1855E+03	.1405E+03	0	.8435E+06
1186.90	.8500E+06	0	.1856E+03	.1404E+03	0	.8435E+06
1278.20	.8500E+06	0	.1856E+03	.1404E+03	0	.8435E+06
1369.50	.8500E+06	0	.1856E+03	.1405E+03	0	.8435E+06
1460.80	.8500E+06	0	.1856E+03	.1405E+03	0	.8435E+06
1552.10	.8500E+06	0	.1856E+03	.1403E+03	0	.8435E+06
1643.40	.8500E+06	0	.8771E+02	.1861E+03	0	.8424E+06
1734.70	.8500E+06	0	.1168E+03	.1814E+03	0	.8445E+06
1826.00	.8500E+06	0	.1079E+03	.1371E+03	0	.8434E+06
1917.30	.8500E+06	0	.9176E+02	.1803E+03	0	.8426E+06
2008.60	.8500E+06	0	.1188E+03	.1828E+03	0	.8444E+06
2099.90	.8500E+06	0	.1875E+03	.1375E+03	0	.8434E+06
2191.20	.8500E+06	0	.1860E+03	.1401E+03	0	.8435E+06
2282.50	.8500E+06	0	.1857E+03	.1401E+03	0	.8435E+06
2373.80	.8500E+06	0	.1861E+03	.1402E+03	0	.8435E+06
2465.10	.8500E+06	0	.1859E+03	.1402E+03	0	.8435E+06
2556.40	.8500E+06	0	.1868E+03	.1402E+03	0	.8435E+06
2647.70	.8500E+06	0	.1859E+03	.1402E+03	0	.8435E+06
2739.00	.8500E+06	0	.1859E+03	.1402E+03	0	.8435E+06

1

RUN # 1	CUMULATIVE INJECTION		CUMULATIVE	PRODUCTION		
CUM. TIME [DAYS]	AIR [SCF]	WATER [STB]	OIL [STB]	WATER [STB]	HC-GAS [SCF]	AIR [SCF]
91.30	.7760E+08	0	0	.1728E+05	.9364E+06	.7656E+08
182.60	.1552E+09	0	0	.2983E+05	.9364E+06	.1532E+09

273.90	.2328E+09	0	.2194E+04	.4840E+05	.9364E+06	.2304E+09
365.20	.3104E+09	0	.8011E+04	.6367E+05	.9364E+06	.3074E+09
456.50	.3880E+09	0	.1626E+05	.7767E+05	.9364E+06	.3844E+09
547.80	.4656E+09	0	.2561E+05	.9054E+05	.9364E+06	.4614E+09
639.10	.5432E+09	0	.3521E+05	.1034E+06	.9364E+06	.5384E+09
730.40	.6208E+09	0	.4485E+05	.1162E+06	.9364E+06	.6154E+09
821.70	.6984E+09	0	.5448E+05	.1290E+06	.9364E+06	.6924E+09
913.00	.7761E+09	0	.6411E+05	.1419E+06	.9364E+06	.7694E+09
1004.30	.8537E+09	0	.7374E+05	.1547E+06	.9364E+06	.8465E+09
1095.60	.9313E+09	0	.8330E+05	.1675E+06	.9364E+06	.9235E+09
1186.90	.1009E+10	0	.9302E+05	.1803E+06	.9364E+06	.1000E+10
1278.20	.1086E+10	0	.1027E+06	.1932E+06	.9364E+06	.1077E+10
1369.50	.1164E+10	0	.1123E+06	.2060E+06	.9364E+06	.1154E+10
1460.80	.1242E+10	0	.1219E+06	.2188E+06	.9364E+06	.1232E+10
1552.10	.1319E+10	0	.1316E+06	.2316E+06	.9364E+06	.1309E+10
1643.40	.1397E+10	0	.1396E+06	.2446E+06	.9364E+06	.1385E+10
1734.70	.1474E+10	0	.1593E+06	.2579E+06	.9364E+06	.1463E+10
1826.00	.1552E+10	0	.1601E+06	.2704E+06	.9364E+06	.1540E+10
1917.30	.1630E+10	0	.1685E+06	.2869E+06	.9364E+06	.1616E+10
2008.60	.1707E+10	0	.1793E+06	.2962E+06	.9364E+06	.1694E+10
2099.90	.1785E+10	0	.1891E+06	.3088E+06	.9364E+06	.1771E+10
2191.20	.1863E+10	0	.1988E+06	.3216E+06	.9364E+06	.1848E+10
2282.50	.1940E+10	0	.2085E+06	.3344E+06	.9364E+06	.1925E+10
2373.80	.2018E+10	0	.2182E+06	.3472E+06	.9364E+06	.2002E+10
2465.10	.2095E+10	0	.2278E+06	.3600E+06	.9364E+06	.2079E+10
2556.40	.2173E+10	0	.2375E+06	.3728E+06	.9364E+06	.2156E+10
2647.70	.2251E+10	0	.2472E+06	.3856E+06	.9364E+06	.2233E+10
2739.00	.2328E+10	0	.2568E+06	.3984E+06	.9364E+06	.2310E+10
RECOVERY EFFICIENCY (FRACTION)			.4897	.6537	1.0000	.9928

10.1.2 Polymer Flood Model Input and Output

The following pages contain output from a proprietary software program which uses Jones' (1983) polymer flooding predictive model. Many options for the user of this program exist, both in Jones' original source code and in this proprietary version.

TITLE INFORMATION

SHANNON POLYMER FLOOD BASE CASE
10-ACRE 5-SPOT

CASE CONTROLS

RESERVOIR CALCULATION METHOD	1	SWITCH
PRODUCTION RESULTS REPORT FREQUENCY	2	SWITCH
CALCULATION RESULTS OUTPUT EXTENT	1	SWITCH

RESERVOIR PROPERTIES

PATTERN AREA	10.0	ACRES
FORMATION DEPTH	550.0	FEET
EFFECTIVE WELLBORE RADIUS	0.72	FEET
LAYER TREATMENT METHOD (STATISTICAL PERMEABILITY DISTRIBUTION)	2	SWITCH
DYKSTRA-PARSONS COEFFICIENT	0.80	UNITLESS
HIGH PERMEABILITY LOCATION OPTION (HIGHEST PERMEABILITY LAYER ON TOP)	1	SWITCH
THICKNESS OF RESERVOIR	76.0	FEET

FLUID PROPERTIES AND SATURATIONS AT RESERVOIR CONDITIONS

IRREDUCIBLE WATER SATURATION		
LAYER (1) =	0.400	FRACTION
LAYER (2) =	0.400	FRACTION
LAYER (3) =	0.400	FRACTION
LAYER (4) =	0.400	FRACTION
LAYER (5) =	0.400	FRACTION
RESIDUAL OIL SATURATION		
LAYER (1) =	0.250	FRACTION
LAYER (2) =	0.250	FRACTION
LAYER (3) =	0.250	FRACTION
LAYER (4) =	0.250	FRACTION
LAYER (5) =	0.250	FRACTION
OIL VISCOSITY	10.000	CP
WATER VISCOSITY	1.000	CP
OIL DENSITY	54.000	LBS/CUFT
WATER DENSITY	62.400	LBS/CUFT
OIL FORMATION VOLUME FACTOR	1.010	RB/STB
WATER FORMATION VOLUME FACTOR	1.000	RB/STB
GAS FORMATION VOLUME FACTOR	10.000	SCF/RB
DISSOLVED GAS OIL RATIO (BP)	32.000	SCF/STB
INITIAL WATER SATURATION	0.520	FRACTION
INITIAL GAS SATURATION	0.030	FRACTION

ROCK PROPERTIES

```
POROSITY
   LAYER ( 1) =                                0.198  FRACTION
   LAYER ( 2) =                                0.198  FRACTION
   LAYER ( 3) =                                0.198  FRACTION
   LAYER ( 4) =                                0.198  FRACTION
   LAYER ( 5) =                                0.198  FRACTION
PERMEABILITY
   LAYER ( 1) =                              773.702  MD
   LAYER ( 2) =                              133.763  MD
   LAYER ( 3) =                               56.288  MD
   LAYER ( 4) =                               24.125  MD
   LAYER ( 5) =                                7.122  MD
 (THICKNESS AVERAGED PERMEABILITY)           200.000  MD
CAPILLARY PRESSURE METHOD                          3  SWITCH
 (CAPILLARY PRESSURE DEFAULT DATA USED)
CAPILLARY PRESSURE SCALING FACTOR
   LAYER ( 1) =                                2.752  UNITLESS
   LAYER ( 2) =                                4.534  UNITLESS
   LAYER ( 3) =                                5.810  UNITLESS
   LAYER ( 4) =                                7.416  UNITLESS
   LAYER ( 5) =                               10.520  UNITLESS
CAPILLARY PRESSURE EXPONENT
   LAYER ( 1) =                               0.0010  UNITLESS
   LAYER ( 2) =                               0.0010  UNITLESS
   LAYER ( 3) =                               0.0010  UNITLESS
   LAYER ( 4) =                               0.0010  UNITLESS
   LAYER ( 5) =                               0.0010  UNITLESS


RELATIVE PERMEABILITY DATA
--------------------------

RELATIVE PERMEABILITY METHOD                       2  SWITCH
 (EXPONENT METHOD USED)
   LAYER ( 1)
   ENDPOINT RELATIVE PERMEABILITY TO OIL      1.0000  UNITLESS
   ENDPOINT RELATIVE PERMEABILITY TO WATER    0.2500  UNITLESS
   EXPONENT IN EQUATION FOR KRO               2.5000  UNITLESS
   EXPONENT IN EQUATION FOR KRW               1.2000  UNITLESS
   LAYER ( 2)
   ENDPOINT RELATIVE PERMEABILITY TO OIL      1.0000  UNITLESS
   ENDPOINT RELATIVE PERMEABILITY TO WATER    0.2500  UNITLESS
   EXPONENT IN EQUATION FOR KRO               2.5000  UNITLESS
   EXPONENT IN EQUATION FOR KRW               1.2000  UNITLESS
   LAYER ( 3)
   ENDPOINT RELATIVE PERMEABILITY TO OIL      1.0000  UNITLESS
   ENDPOINT RELATIVE PERMEABILITY TO WATER    0.2500  UNITLESS
   EXPONENT IN EQUATION FOR KRO               2.5000  UNITLESS
   EXPONENT IN EQUATION FOR KRW               1.2000  UNITLESS
   LAYER ( 4)
   ENDPOINT RELATIVE PERMEABILITY TO OIL      1.0000  UNITLESS
   ENDPOINT RELATIVE PERMEABILITY TO WATER    0.2500  UNITLESS
   EXPONENT IN EQUATION FOR KRO               2.5000  UNITLESS
   EXPONENT IN EQUATION FOR KRW               1.2000  UNITLESS
   LAYER ( 5)
   ENDPOINT RELATIVE PERMEABILITY TO OIL      1.0000  UNITLESS
   ENDPOINT RELATIVE PERMEABILITY TO WATER    0.2500  UNITLESS
   EXPONENT IN EQUATION FOR KRO               2.5000  UNITLESS
   EXPONENT IN EQUATION FOR KRW               1.2000  UNITLESS
```

POLYMER PROPERTY DATA

POLYMER INTRINSIC VISCOSITY COEFFICIENT	36.000	DL/GRAM
POLYMER VISCOSITY COEFFICIENT	0.200	UNITLESS
MIXING PARAMETER	1.000	FRACTION
PORE VOLUME INACCESSIBLE TO POLYMER	0.200	FRACTION
RELATIVE PERMEABILITY REDUCTION OPTION (RESIDUAL RESISTANCE FACTOR KNOWN)	1	SWITCH
RESIDUAL RESISTANCE FACTOR	2.790	UNITLESS
POLYMER ADSORPTION OPTION (FIXED POLYMER ADSORPTION RATE)	1	SWITCH
POLYMER ADSORPTION RATE	150.0	LBS/ACFT

INJECTION CONTROL DATA

WATER CUT AT START OF POLYMER INJECTION	0.000	FRACTION
PORE VOLUMES INJECTED PRIOR TO POLYMER	0.00	PORE VOL
POLYMER PORE VOLUMES INJECTED	1.000	PORE VOL
POLYMER INJECTED CONCENTRATION	700.0	PPM
CONCENTRATION GRADIENT DURING INJECTION	1	SWITCH
SHEAR RATE CALCULATION COEFFICIENT	2.000	UNITLESS
POLYMER POWER LAW EXPONENT	0.700	UNITLESS
INJECTION CONTROL METHOD (CONSTANT PRESSURE DROP METHOD USED)	1	SWITCH
PRESSURE DROP FROM INJECTOR TO PRODUCER	500.0	PSI
MAXIMUM WELL INJECTION RATE	700.0	STB/D/WL
WATER FRACTIONAL FLOW CUT OFF POINT	0.990	FRACTION

*** END OF INPUT PROCESSING ***

NO WARNINGS
NO ERRORS

SHANNON POLYMER FLOOD BASE CASE
10-ACRE 5-SPOT

*** SUMMARY ***

PROJECT LIFE	21.7 YEARS
TOTAL OIL PRODUCED	233.429 MSTB
TOTAL GAS PRODUCED	7.791 MMSCF
TOTAL PORE VOLUMES OF WATER INJECTED	0.919 PORE VOL
TOTAL WATER INJECTED	1073.017 MSTB
TOTAL WATER PRODUCED	802.231 MSTB
TOTAL POLYMER INJECTED	263171.600 LBS
MAXIMUM OIL PRODUCTION RATE	235.5 STB/D
MAXIMUM GAS PRODUCTION RATE	9.1 MSCF/D
MAXIMUM WATER INJECTION RATE	313.9 STB/D
MAXIMUM WATER PRODUCTION RATE	136.3 STB/D
MAXIMUM POLYMER INJECTION RATE	77.0 LBS/D

10.2.1 In-Situ Combustion Spreadsheet Model

The following pages contain five spreadsheets which were used in the evaluation of economics for in-situ combustion in the Shannon formatic . at NPR-3.

Capital costs were computed as shown on the "EOR Capital Costs Estimation Worksheet". The number of injection and of production wells were specified and the "Injection Well Drilling Cost" and "Production Well Drilling Cost" were automatically read from the "Drilling and Completion Costs" spreadsheet. "Injection Well Cost" and "Production Well Cost" used in the capital costs calculation were then found by multiplying the number of each type of well by the respective drilling cost. Other capital costs were simply entered into the spreadsheet and summed to arrive at the "Total Capital Cost".

For the 10-acre base case, it was assumed that two patterns could be served by one air compressor costing $240,000, housed in a building costing $30,000. Therefore, the "per Unit Area" cost for these items was taken as $120,000 and $15,000, respectively, for these items. Additionally, a $100,000 capital expense for steam pre-heating the reservoir and soaking the wellbore with linseed oil, in each injector, was assumed to be necessary. Also assumed as capital expenses were gas-monitoring equipment, quench water systems, ignition equipment, and safety equipment. For the base case of four 2.5-acre patterns, the aforementioned costs were multiplied by a factor of 4. It was also assumed that the equivalent of one existing production well per 10 acres would require a $40,000 workover.

10.2 Economic Analysis Model Input and Output

Economic analyses were performed using Microsoft® Multiplan® on an Apple® Macintosh™. An example set of spreadsheets for each process is presented herein. In-situ combustion predictions are contained in section 10.2.1, section 10.2.2 has analyses for polymer flooding, and steamflooding analyses are shown in section 10.2.3.

For each EOR process investigated, five spreadsheets were composed:

- Capital Costs
- Drilling Costs (Sub-Set of Capital Costs)
- Operating Costs
- Gross Revenues
- Discounted Cash Flow Analysis

Since limited data were available, the spreadsheets are relatively simple. However, the drilling costs spreadsheet lists data from wells drilled in 1984, and is a small example of the detail to which these tools may be extended. Additionally, each of the spreadsheets were linked together so that a change in one parameter would be reflected in other calculations. For example, if the days for drilling an injection well were to increase from two to three, one would merely enter "3" in the appropriate cell in the drilling costs spreadsheet, and the net present value in the DCF analysis spreadsheet would change appropriately. A brief discussion of certain formulas and assumptions accompanies each section.

10	913.03	85.93	98257.4	512.77	431574.3	2.753	3573.96	.2151	70.00
11	1004.33	83.13	105792.9	513.20	478229.4	2.660	3816.42	.2107	70.00
12	1095.63	82.03	113099.3	514.12	525168.8	2.561	4050.63	.2065	70.00
13	1186.93	79.14	120233.3	514.33	572097.0	2.500	4278.91	.2026	70.00
14	1278.23	75.92	127163.4	514.38	619060.1	2.429	4500.68	.1990	70.30
15	1369.50	73.27	133853.0	515.29	666106.2	2.345	4714.75	.1955	70.00
16	1460.80	71.79	140407.2	515.16	713140.5	2.297	4924.49	.1922	70.00
17	1552.10	69.89	146789.4	515.53	760208.4	2.237	5128.68	.1891	70.00
18	1643.40	68.59	153042.8	515.49	807272.8	2.192	5328.82	.1863	70.00
19	1734.70	66.92	159152.6	515.75	854361.1	2.141	5524.27	.1835	70.00
20	1826.00	65.65	165144.2	515.72	901446.5	2.101	5716.07	.1809	70.00
21	1917.30	64.12	170999.0	516.04	949561.2	2.052	5903.39	.1784	70.00
22	2008.60	63.07	176755.9	515.95	995667.0	2.018	6087.64	.1760	70.00
23	2099.90	61.57	182377.5	516.34	1042808.9	1.977	6267.53	.1737	70.00
24	2191.20	60.67	187916.5	516.19	1089937.0	1.941	6444.78	.1715	70.00
25	2282.50	59.39	193338.4	516.47	1137790.9	1.903	6618.29	.1694	70.00
26	2373.80	58.47	198677.1	516.43	1184240.6	1.371	6789.12	.1674	70.00
27	2465.10	57.59	203935.2	516.39	1231386.9	1.843	6957.38	.1655	70.00
28	2556.40	56.09	207055.0	517.14	1279631.7	1.794	7121.21	.1636	70.00
29	2647.70	44.39	213108.1	530.71	1327055.4	1.794	7295.04	.1610	70.00
30	2739.00	32.71	216094.6	544.29	1376748.2	1.947	7380.61	.1578	70.00
31	2830.30	49.68	220630.3	529.42	1425084.1	1.590	7525.75	.1559	70.00
32	2921.60	54.10	225569.5	522.94	1472919.7	1.731	7683.80	.1544	70.00
33	3012.90	54.66	230559.9	521.59	1520541.1	1.749	7943.50	.1530	70.00
34	3104.20	57.52	235811.5	515.46	1567602.2	1.941	8011.55	.1519	70.00
35	3195.50	51.44	240508.4	515.12	1614532.3	1.646	8161.85	.1505	70.00
36	3286.80	55.69	245136.0	518.27	1661950.7	1.622	8309.93	.1492	70.00
37	3378.10	52.21	249719.7	518.68	1709306.0	1.697	8456.61	.1478	70.00
38	3469.40	47.89	254894.2	517.46	1756549.8	1.530	8596.29	.1465	70.00
39	3560.70	45.45	259234.1	516.18	1803676.9	1.454	8729.37	.1450	70.00
40	3652.00	39.75	251863.1	519.93	1851146.4	1.272	8845.20	.1434	70.00

	TIME	RATE	INJECTION	RATE	HEAT INJ.	PRESSURE	TEMP.	QUALITY
	(DAYS)	(BCWE/D)	(BCWE)	(BTU/D)	(BTU)	(PSIA)	(DEG.F)	
1	91.30	500.00	45650.0	.1754E+09	.1601E+11	498.43	465.42	.7607
2	182.60	500.00	91300.0	.1759E+09	.3207E+11	474.97	460.60	.7632
3	273.90	500.00	136950.0	.1761E+09	.4815E+11	459.56	456.97	.7644
4	365.20	500.00	182600.0	.1762E+09	.6424E+11	446.76	454.30	.7652
5	456.50	500.00	228250.0	.1763E+09	.8034E+11	437.56	452.19	.7657
6	547.80	500.00	273900.0	.1764E+09	.9644E+11	430.03	450.42	.7662
7	639.10	500.00	319550.0	.1764E+09	.1125E+12	423.64	448.90	.7665
8	730.40	500.00	365200.0	.1765E+09	.1287E+12	418.11	447.59	.7668
9	821.70	500.00	410850.0	.1765E+09	.1448E+12	413.19	446.38	.7671
10	913.00	500.00	456500.0	.1765E+09	.1609E+12	408.85	445.33	.7673
11	1004.30	500.00	502150.0	.1766E+09	.1770E+12	404.91	444.36	.7675
12	1095.60	500.00	547800.0	.1766E+09	.1931E+12	401.36	443.49	.7677
13	1186.90	500.00	593450.0	.1766E+09	.2093E+12	398.04	442.65	.7679
14	1278.20	500.00	639100.0	.1766E+09	.2254E+12	394.98	441.89	.7681
15	1369.50	500.00	684750.0	.1766E+09	.2415E+12	392.17	441.17	.7682
16	1460.80	500.00	730400.0	.1767E+09	.2576E+12	389.41	440.47	.7683
17	1552.10	500.00	776050.0	.1767E+09	.2739E+12	386.73	439.79	.7685
18	1643.40	500.00	821700.0	.1767E+09	.2899E+12	384.05	439.13	.7686
19	1734.70	500.00	867350.0	.1767E+09	.3060E+12	381.42	438.42	.7687
20	1826.00	500.00	913000.0	.1767E+09	.3222E+12	378.77	437.73	.7689
21	1917.30	500.00	958650.0	.1767E+09	.3383E+12	376.14	437.05	.7689
22	2008.60	500.00	1004300.0	.1767E+09	.3544E+12	373.49	436.35	.7690
23	2099.90	500.00	1049950.0	.1768E+09	.3706E+12	370.80	435.64	.7691
24	2191.20	500.00	1095600.0	.1768E+09	.3867E+12	368.04	434.91	.7691
25	2282.50	500.00	1141250.0	.1768E+09	.4029E+12	365.22	434.16	.7692
26	2373.80	500.00	1186900.0	.1768E+09	.4190E+12	362.26	433.37	.7693
27	2465.10	500.00	1232550.0	.1768E+09	.4351E+12	359.13	432.52	.7694
28	2556.40	500.00	1278200.0	.1768E+09	.4513E+12	355.95	431.66	.7694
29	2647.70	500.00	1323850.0	.1768E+09	.4674E+12	352.49	430.71	.7695
30	2739.00	500.00	1369500.0	.1768E+09	.4836E+12	348.49	429.60	.7696
31	2830.30	500.00	1415150.0	.1768E+09	.4997E+12	343.59	428.29	.7696
32	2921.60	500.00	1460800.0	.1768E+09	.5159E+12	337.61	426.55	.7697
33	3012.90	500.00	1506450.0	.1769E+09	.5320E+12	329.74	424.29	.7697
34	3104.20	500.00	1552100.0	.1769E+09	.5482E+12	316.39	420.49	.7698
35	3195.50	500.00	1597750.0	.1769E+09	.5643E+12	253.34	397.43	.7698
36	3286.80	500.00	1643400.0	.1769E+09	.5805E+12	130.07	344.17	.7699
37	3378.10	500.00	1689050.0	.1769E+09	.5966E+12	130.08	344.17	.7699
38	3469.40	500.00	1734700.0	.1769E+09	.6128E+12	130.08	344.17	.7700
39	3560.70	500.00	1780350.0	.1769E+09	.6289E+12	130.08	344.17	.7700
40	3652.00	500.00	1826000.0	.1769E+09	.6451E+12	130.08	344.17	.7701

STEAM FLOOD PATTERN PRODUCTION REPORT

	TIME	OIL RATE	CUM. OIL PRODUCTION	WATER RATE	CUM. WATER PRODUCTION	HYDROCARBON GAS RATE	CUM. H.C. GAS PROD.	CUM. OIL/ STEAM RATIO	BH PROD. PRESSURE
	(DAYS)	(B/D)	(BPL)	(B/D)	(BPL)	(MSCF/D)	(MSCF)	(VOL/VOL)	(PSIA)
1	91.30	81.07	7402.1	199.22	18189.1	7.320	668.32	.1621	70.00
2	182.60	159.51	21974.4	475.36	61509.3	5.072	1131.43	.2396	70.00
3	273.90	133.50	34062.5	493.70	106664.2	4.272	1521.45	.2487	70.00
4	365.20	120.33	45048.7	500.37	152347.9	3.851	1873.01	.2467	70.00
5	456.50	110.88	55171.6	504.63	198420.8	3.549	2196.94	.2417	70.00
6	547.80	103.64	64634.2	507.54	244756.8	3.317	2499.74	.2360	70.00
7	639.10	98.28	73626.7	509.19	291247.8	3.145	2786.86	.2303	70.00
8	730.40	93.41	82135.2	510.79	337982.7	2.989	3059.78	.2249	70.00
9	821.70	90.07	90358.4	511.24	384558.7	2.882	3322.92	.2199	70.00

FLUID PROPERTIES

OIL GRAVITY	.9654	G/G
GAS GRAVITY	.8000	AIR=1.0
OIL VISCOSITY AT SURFACE	10.00	CP
SOLUTION GAS OIL RATIO	32.00	SCF/STB

PROPERTY TABLE

	1	2	3	4
ESTIMATED TEMPERATURE , DEG.F	65.00	65.00	265.49	465.95
OIL VISCOSITY , CP	9.05	9.05	.96	.37
WATER VISCOSITY , CP	1.0332	1.0332	.2110	.0857
GAS VISCOSITY , CP	.0102	.0102	.0102	.0189
OIL DENSITY ,LB/CU.FT	53.92	53.92	49.99	45.25
WATER DENSITY , LB/CU.FT	62.29	62.29	56.66	51.03
GAS DENSITY , LB/CU.FT	.2879	.2879	.2879	1.1394
RESIDUAL OIL SATURATION TO WATER	.2500	.2500	.2500	.2500
RESIDUAL OIL SATURATION TO GAS	.4000	.4000	.4083	.0637
RESIDUAL WATER SATURATION	.4100	.4100	.5000	.5000
RESIDUAL GAS SATURATION	0	0	0	0

STEAM CONDITIONS

STEAM TEMPERATURE	466.0	DEG.F
STEAM PRESSURE	500.0	PSIA
LATENT HEAT	764.0	BTU/LB
HEAT INJECTION RATE	172351800.	BTU/DAY
MASS INJECTION RATE	175260.	LB/DAY
STEAM SATURATION IN ZONE 4	.4068	FRACTION

WELL INFORMATION

WELL DEPTH	550.0	FEET
SURFACE TEMPERATURE	60.0	DEG F
OUTER RADIUS OF INSULATION	.130	FEET
OUTER RADIUS OF TUBING	.120	FEET
OUTER RADIUS OF CASING	.229	FEET
RADIUS OF INJECTOR (OUTER RADIUS OF CEMENTING)	.328	FEET
RADIUS OF PRODUCER	.328	FEET

TIME STEP SCHEDULE (1)

TIME SINCE START OF INJECTION	120.00	MONTHS
DEBUG PRINT CONTROL	0	

CASE CONDITIONS

BOTTOM HOLE INJECTION PRESSURE	500.0	PSIA
BOTTOM HOLE PRODUCTION PRESSURE	70.0	PSIA
INJECTION RATE	500.0	B/D(CWE)
SURFACE STEAM QUALITY	.8000	
SKIN FACTOR OF INJECTOR	0	
SKIN FACTOR OF PRODUCER	.20	

STEAM FLOOD PATTERN INJECTION REPORT

INJECTION	CUM.	HEAT INJ.	CUM.	SH INJ.	BH	BH STEAM

1

```
***************************************
*                                     *
*     STEAM FLOOD PREDICTIVE MODEL    *
*                                     *
***************************************

SHANNON STEAMFLOOD PREDICTION - 10-ACRE 5-SPOT BASE CASE

CASE CONTROLS
-------------
 WELL CONSTRAINT CONTROL ..............         2  IWCON
      IWCON = 0 : CONSTANT INJ. RATE
            = 1 : CONSTANT INJ. PRESSURE
            = 2 : CONSTANT(AVERAGE) INJ. PRESSURE
                  AND CONSTANT(AVERAGE) INJ. RATE

 RESIDUAL SATURATION CONTROL ...........        1  IRSAT
      IRSAT = -1 : ALL RESIDUAL SATURATIONS ARE DEFAULT
            =  0 : SWR(1) NEED TO BE INPUT
            =  1 : SWR(1),SORW(1),AND SORG(1) NEED TO BE INPUT
            =  2 : SWR(1),SORW(1),SORG(1),AND SORG(4) NEED TO BE INPUT
            =  3 : SWR(1),SWR(3),SWR(4),SORW(1),SORG(1),SORW(3), AND SORG(4) NEED TO BE INPUT

FORMATION PROPERTIES
--------------------
  TOTAL PATTERN AREA ....................     10.00  ACRES
  INITIAL TEMPERATURE ...................      65.0  DEG.F
  FORMATION GROSS THICKNESS .............      97.0  FEET
  FORMATION NET THICKNESS (PAY) .........      76.0  FEET
  FORMATION PERMEABILITY ................     200.0  MD
  FORMATION POROSITY ....................     .1930  FRACTION
  ROCK DENSITY AT STEAM TEMP ............    165.00  LB/CU.FT
  ROCK HEAT CAPACITY ....................     .2100  BTU/LB F
  ROCK THERMAL CONDUCTIVITY .............   35.0000  BTU/DAY-F-FT
  REL. PERM. TO WATER AT SOR ............     .2500
  REL. PERM. TO OIL AT SCW ..............    1.0000
  REL. PERM. TO GAS AT SOR ..............    1.0000
  EXPONENT FOR KRW IN OIL-WATER EQN .....    1.0000
  EXPONENT FOR KRG IN OIL-WATER EQN .....    3.0000
  EXPONENT FOR KROW IN OIL-WATER EQN ....    3.2000
  EXPONENT FOR KROG IN GAS-OIL EQN ......    2.0000

INITIAL CONDITIONS
------------------
  INITIAL OIL SATURATION ................     .4500  FRACTION
  INITIAL WATER SATURATION ..............     .5200  FRACTION
  INITIAL GAS SATURATION ................     .0300  FRACTION
  OIL DENSITY AT STEAM TEMP .............   45.2539  LB/CU.FT
  WATER DENSITY AT STEAM TEMP ...........   51.0253  LB/CU.FT
  OIL HEAT CAPACITY .....................     .5455  BTU/LB F
  WATER HEAT CAPACITY ...................    1.0500  BTU/LB F
  INITIAL OIL VISCOSITY .................       9.1  CP
  OIL VISCOSITY AT STEAM TEMP ...........      .372  CP
  INITIAL OIL IN PLACE ..................   512097.  RBBL
  INITIAL WATER IN PLACE ................   591757.  RBBL
```

Steam Flood Predictive Model [Arima (1984)] Input Data

R1	TITLE	=	
R2:	IWCON	=	Well Constraint Index (0,1,2)
	IRSAT	=	Residual Saturation Control Index (0,1,2,3)
R3:	TF	=	Initial Reservoir Temperature, °F
	PF	=	Initial Reservoir Pressure, psia
	HN	=	Net Thickness, ft
	HT	=	Gross Thickness, ft
	PERM	=	Permeability, md
	POR	=	Porosity, fraction
	SWI	=	Initial Water Saturation, fraction
	SGI	=	Initial Gas Saturation, fraction
	FCON	=	Formation Thermal Conductivity, Btu/D ft °F
	PATN	=	5-Spot Pattern Area, acres
	ALP	=	Dip Angle of Reservoir, radians
R4	GAMO	=	Specific Gravity of Oil (Water = 1.0)
	GAMG	=	Specific Gravity of Gas (Air = 1.0)
	VISO1	=	Oil Viscosity at Surface Temperature, cp
	RSOL	=	Solution Gas/Oil Ratio, scf/stb
R5:	SWR1	=	Residual Water Saturation, Cold Zones 1&2
	SWR3	=	Residual Water Saturation, Condensate Zone 3
	SWR4	=	Residual Water Saturation, Steam Zone 4
	SORW1	=	Residual Oil to Water, Cold Zones 1&2
	SORW3	=	Residual Oil to Water, Condensate Zone 3
	SORG1	=	Residual Oil to Gas, Cold Zones 1&2
	SORG4	=	Residual Oil to Gas, Steam Zone 4
R6:	DAYR	=	Time Step Size, days
R7:	RKWRO	=	Relative Permeability to Water at Sor
	RKOCW	=	Relative Permeability to Oil at Scw
	RKGRO	=	Relative Permeability to Gas at Sor
	W	=	Exponent for Relative Permeability to Water
	G	=	Exponent for Relative Permeability to Gas
	OW	=	Exponent for Relative Permeability to Oil
	OG	=	Exponent for Relative Permeability to Steam
R8:	DEPTH	=	Depth to Formation Top, ft
	TSURF	=	Mean Annual Surface Temperature, °F
	RINS	=	Outer Radius of Tubing Insulation, ft
	RTO	=	Outer Radius of Injection Tubing, ft
	RCO	=	Outer Radius of Injection Well Casing, ft
	RINJ	=	Outer Radius of Cement Sheath, Injector, ft
	RPRO	=	Inner Radius of Production String, ft
R9:	TMAX	=	Number of Time Steps Used
	IPRINT	=	Debug Print Control Index
R10:	PINJ	=	Bottom Hole Steam Injection Pressure, psia
	PPRO	=	Bottom Hole Production Pressure, psia
	RATINJ	=	Steam Injection Rate, BCWEPD
	XX	=	Surface Injection Steam Quality, wgt fraction
	SHOT	=	Injection Well Skin Factor
	SCOLD	=	Production Well Skin Factor

10.1.3 Steamflood Model Input and Output

Sample output for the steam flood predictive model given by Arima(1984) is contained in the following pages. Additionally provided is an input data template used in the course of this study which describes the input variables for the model as listed in the FORTRAN source code. As with the two other models discussed, Arima provides various user options which are well-documented in the output as show herein. Figure 10.1 is provided for clarification of the variables used in wellbore heat loss calculations.

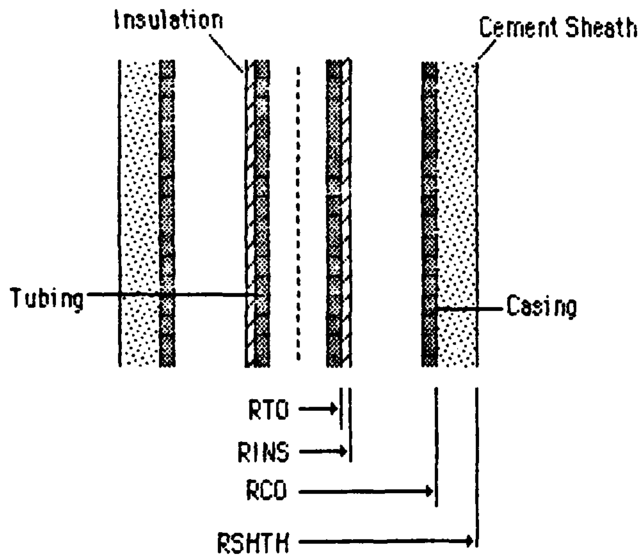

Fig. 10.1. A diagram which illustrates the wellbore heat loss variables required in the steamflood predictive model given by Arima (1984).

INJECTION SUMMARY

TIME YEAR/QTR	INJECTION RATES WATER STB/D	POLYMER LBS/DAY	CUMULATIVE INJECTION WATER MST3	POLYMER LBS	PV INJECTED WATER
12/ 1	115.	28.	737.3	180947.	0.632
12/ 2	113.	28.	748.1	183482.	0.641
12/ 3	112.	27.	758.3	185992.	0.650
12/ 4	111.	27.	768.5	188476.	0.658
13/ 1	110.	27.	778.5	190937.	0.667
13/ 2	109.	27.	788.4	193375.	0.675
13/ 3	108.	26.	798.3	195739.	0.684
13/ 4	107.	26.	808.0	198184.	0.692
14/ 1	106.	26.	817.7	200560.	0.700
14/ 2	105.	26.	827.3	202917.	0.709
14/ 3	104.	26.	836.9	205253.	0.717
14/ 4	103.	25.	846.3	207565.	0.725
15/ 1	102.	25.	855.6	209855.	0.733
15/ 2	101.	25.	864.9	212126.	0.741
15/ 3	101.	25.	874.1	214379.	0.749
15/ 4	100.	24.	883.2	216614.	0.757
16/ 1	99.	24.	892.2	218828.	0.764
16/ 2	98.	24.	901.2	221027.	0.772
16/ 3	98.	24.	910.1	223213.	0.780
16/ 4	97.	24.	918.9	225383.	0.787
17/ 1	96.	24.	927.7	227536.	0.795
17/ 2	96.	23.	936.4	229675.	0.802
17/ 3	95.	23.	945.1	231802.	0.810
17/ 4	94.	23.	953.7	233913.	0.817
18/ 1	93.	23.	962.2	236004.	0.824
18/ 2	93.	23.	970.7	238083.	0.832
18/ 3	92.	23.	979.1	240148.	0.839
18/ 4	91.	22.	987.5	242195.	0.846
19/ 1	91.	22.	995.8	244229.	0.853
19/ 2	90.	22.	1004.0	246252.	0.860
19/ 3	90.	22.	1012.2	248261.	0.867
19/ 4	89.	22.	1020.4	250256.	0.874
20/ 1	89.	22.	1028.5	252242.	0.881
20/ 2	88.	22.	1036.5	254218.	0.888
20/ 3	88.	21.	1044.5	256179.	0.895
20/ 4	87.	21.	1052.5	258132.	0.902
21/ 1	87.	21.	1060.4	260075.	0.908
21/ 2	86.	21.	1068.3	262002.	0.915

INJECTION SUMMARY

TIME YEAR/QTR	INJECTION RATES WATER STB/D	POLYMER LBS/DAY	CUMULATIVE INJECTION WATER MSTB	POLYMER LBS	PV INJECTED WATER
0/ 1	55.	14.	5.0	1234.	0.004
0/ 2	55.	14.	10.1	2467.	0.009
0/ 3	52.	13.	14.3	3633.	0.013
0/ 4	52.	13.	19.6	4798.	0.017
1/ 1	153.	39.	34.0	8327.	0.029
1/ 2	309.	76.	62.2	15244.	0.053
1/ 3	295.	72.	89.1	21846.	0.076
1/ 4	282.	69.	114.9	28167.	0.098
2/ 1	273.	67.	139.3	34237.	0.120
2/ 2	263.	65.	163.9	40178.	0.140
2/ 3	253.	62.	186.9	45831.	0.160
2/ 4	244.	60.	209.1	51294.	0.179
3/ 1	237.	58.	230.3	56607.	0.198
3/ 2	231.	57.	251.9	61780.	0.216
3/ 3	224.	55.	272.3	66736.	0.233
3/ 4	216.	53.	292.0	71611.	0.250
4/ 1	208.	51.	310.9	76261.	0.266
4/ 2	202.	50.	329.4	80778.	0.282
4/ 3	195.	48.	347.2	85148.	0.297
4/ 4	190.	47.	364.5	89402.	0.312
5/ 1	184.	45.	381.3	93511.	0.327
5/ 2	179.	44.	397.6	97506.	0.341
5/ 3	173.	43.	413.4	101388.	0.354
5/ 4	169.	41.	428.9	105170.	0.367
6/ 1	165.	41.	443.9	108873.	0.380
6/ 2	162.	40.	458.7	112501.	0.393
6/ 3	159.	39.	473.2	116048.	0.405
6/ 4	155.	38.	487.3	119525.	0.417
7/ 1	152.	37.	501.2	122929.	0.429
7/ 2	149.	37.	514.8	126265.	0.441
7/ 3	146.	36.	528.2	129538.	0.452
7/ 4	144.	35.	541.3	132753.	0.464
8/ 1	141.	35.	554.2	135913.	0.475
8/ 2	139.	34.	566.3	139026.	0.486
8/ 3	137.	34.	579.4	142095.	0.496
8/ 4	135.	33.	591.7	145121.	0.507
9/ 1	133.	33.	603.8	148101.	0.517
9/ 2	131.	32.	615.8	151035.	0.527
9/ 3	129.	32.	627.6	153926.	0.538
9/ 4	127.	31.	639.2	156775.	0.548
10/ 1	126.	31.	650.7	159587.	0.557
10/ 2	124.	30.	662.0	162364.	0.567
10/ 3	123.	30.	673.2	165108.	0.577
10/ 4	121.	30.	684.3	167822.	0.586
11/ 1	120.	29.	695.2	170508.	0.596
11/ 2	119.	29.	706.0	173164.	0.605
11/ 3	117.	29.	716.7	175789.	0.614
11/ 4	116.	28.	727.3	178382.	0.623

PRODUCTION SUMMARY

TIME YEAR/QTR	<--- CUMULATIVE PRODUCTION OIL MSTB	GAS MMSCF	WATER MSTB --->
12/ 1	227.7	7.6	472.9
12/ 2	228.0	7.6	482.8
12/ 3	228.2	7.6	492.8
12/ 4	228.5	7.6	502.7
13/ 1	228.7	7.6	512.5
13/ 2	228.9	7.6	522.2
13/ 3	229.1	7.7	531.9
13/ 4	229.4	7.7	541.4
14/ 1	229.6	7.7	550.9
14/ 2	229.8	7.7	560.3
14/ 3	230.0	7.7	569.6
14/ 4	230.1	7.7	578.9
15/ 1	230.3	7.7	588.0
15/ 2	230.5	7.7	597.1
15/ 3	230.7	7.7	606.1
15/ 4	230.9	7.7	615.0
16/ 1	231.0	7.7	623.9
16/ 2	231.1	7.7	632.7
16/ 3	231.3	7.7	641.5
16/ 4	231.4	7.7	650.2
17/ 1	231.6	7.7	658.8
17/ 2	231.7	7.7	667.4
17/ 3	231.8	7.7	675.9
17/ 4	232.0	7.7	684.4
18/ 1	232.1	7.7	692.9
18/ 2	232.2	7.8	701.2
18/ 3	232.3	7.8	709.5
18/ 4	232.5	7.8	717.7
19/ 1	232.6	7.8	725.9
19/ 2	232.7	7.8	734.0
19/ 3	232.8	7.8	742.1
19/ 4	232.9	7.8	750.1
20/ 1	233.0	7.8	758.1
20/ 2	233.1	7.8	766.1
20/ 3	233.1	7.8	774.0
20/ 4	233.2	7.8	781.9
21/ 1	233.3	7.8	789.7
21/ 2	233.4	7.8	797.5

PRODUCTION SUMMARY

TIME YEAR/QTR	<--- CUMULATIVE OIL MSTB	PRODUCTION GAS MMSCF	---> WATER MSTB
0/ 1	0.0	0.1	0.0
0/ 2	0.0	0.1	0.0
0/ 3	0.0	0.1	0.0
0/ 4	0.0	0.2	0.0
1/ 1	1.6	0.4	0.0
1/ 2	27.3	1.2	0.0
1/ 3	51.8	2.0	1.9
1/ 4	75.2	2.7	3.8
2/ 1	97.9	3.5	5.9
2/ 2	119.3	4.2	7.8
2/ 3	140.7	4.3	9.7
2/ 4	161.0	5.5	11.5
3/ 1	180.3	6.1	13.7
3/ 2	195.0	6.6	20.0
3/ 3	200.0	6.7	35.3
3/ 4	203.7	6.8	51.2
4/ 1	207.1	6.9	66.7
4/ 2	209.2	7.0	83.0
4/ 3	210.3	7.1	99.2
4/ 4	212.3	7.1	115.1
5/ 1	213.5	7.2	130.6
5/ 2	214.5	7.2	145.9
5/ 3	215.5	7.2	160.7
5/ 4	216.4	7.2	175.2
6/ 1	217.2	7.3	189.5
6/ 2	217.9	7.3	203.5
6/ 3	218.6	7.3	217.3
6/ 4	219.2	7.3	230.9
7/ 1	219.8	7.4	244.2
7/ 2	220.4	7.4	257.2
7/ 3	220.9	7.4	270.0
7/ 4	221.5	7.4	282.6
8/ 1	221.9	7.4	295.0
8/ 2	222.4	7.4	307.2
8/ 3	222.9	7.5	319.2
8/ 4	223.3	7.5	331.1
9/ 1	223.7	7.5	342.9
9/ 2	224.1	7.5	354.4
9/ 3	224.5	7.5	365.8
9/ 4	224.9	7.5	377.1
10/ 1	225.2	7.5	388.2
10/ 2	225.6	7.5	399.1
10/ 3	225.9	7.6	410.0
10/ 4	226.2	7.6	420.7
11/ 1	226.6	7.6	431.4
11/ 2	226.9	7.6	441.9
11/ 3	227.1	7.6	452.3
11/ 4	227.4	7.6	462.6

PRODUCTION SUMMARY

TIME YEAR/QTR	<--- PRODUCING RATES OIL STB/D	GAS MSCF/D	WATER STB/D --->	GOR MSCF/STB	WOR STB/STB
12/ 1	3.	0.	112.	0.03	37.75
12/ 2	3.	0.	110.	0.03	38.67
12/ 3	3.	0.	109.	0.03	39.61
12/ 4	3.	0.	108.	0.03	40.57
13/ 1	3.	0.	107.	0.03	41.50
13/ 2	2.	0.	106.	0.03	42.60
13/ 3	2.	0.	105.	0.03	43.75
13/ 4	2.	0.	105.	0.03	44.78
14/ 1	2.	0.	104.	0.03	45.84
14/ 2	2.	0.	103.	0.03	46.93
14/ 3	2.	0.	102.	0.03	48.04
14/ 4	2.	0.	101.	0.03	49.38
15/ 1	2.	0.	100.	0.03	50.69
15/ 2	2.	0.	100.	0.03	51.82
15/ 3	2.	0.	99.	0.03	52.96
15/ 4	2.	0.	98.	0.03	54.31
16/ 1	2.	0.	97.	0.03	55.76
16/ 2	2.	0.	97.	0.03	56.97
16/ 3	2.	0.	96.	0.03	58.24
16/ 4	2.	0.	95.	0.03	59.67
17/ 1	2.	0.	95.	0.03	61.53
17/ 2	1.	0.	94.	0.03	62.91
17/ 3	1.	0.	94.	0.03	64.33
17/ 4	1.	0.	93.	0.03	66.08
18/ 1	1.	0.	92.	0.03	68.15
18/ 2	1.	0.	92.	0.03	69.33
18/ 3	1.	0.	91.	0.03	70.49
18/ 4	1.	0.	90.	0.03	72.59
19/ 1	1.	0.	90.	0.03	74.20
19/ 2	1.	0.	89.	0.03	75.71
19/ 3	1.	0.	89.	0.03	77.97
19/ 4	1.	0.	88.	0.03	80.96
20/ 1	1.	0.	88.	0.03	83.28
20/ 2	1.	0.	87.	0.03	86.41
20/ 3	1.	0.	87.	0.03	90.99
20/ 4	1.	0.	86.	0.03	94.14
21/ 1	1.	0.	86.	0.03	98.15
21/ 2	1.	0.	85.	0.03	106.06

PRODUCTION SUMMARY

TIME YEAR/QTR	<--- OIL STB/D	PRODUCING RATES GAS MSCF/D	WATER STB/D --->	GOR MSCF/STB	WOR STB/STB
0/ 1	0.	1.	0.	********	0.00
0/ 2	0.	1.	0.	********	0.00
0/ 3	0.	1.	0.	********	0.00
0/ 4	0.	1.	0.	********	0.00
1/ 1	18.	2.	0.	0.11	0.00
1/ 2	281.	9.	0.	0.03	0.00
1/ 3	268.	9.	19.	0.03	0.07
1/ 4	257.	8.	23.	0.03	0.09
2/ 1	249.	8.	22.	0.03	0.09
2/ 2	239.	8.	21.	0.03	0.09
2/ 3	230.	7.	21.	0.03	0.09
2/ 4	222.	7.	20.	0.03	0.09
3/ 1	211.	7.	24.	0.03	0.11
3/ 2	161.	5.	69.	0.03	0.43
3/ 3	55.	2.	168.	0.03	3.03
3/ 4	41.	1.	174.	0.03	4.26
4/ 1	37.	1.	170.	0.03	4.59
4/ 2	23.	1.	179.	0.03	7.79
4/ 3	18.	1.	177.	0.03	9.86
4/ 4	16.	0.	174.	0.03	11.16
5/ 1	13.	0.	170.	0.03	12.75
5/ 2	12.	0.	167.	0.03	14.04
5/ 3	11.	0.	163.	0.03	15.50
5/ 4	9.	0.	159.	0.03	16.89
6/ 1	9.	0.	157.	0.03	17.98
6/ 2	8.	0.	154.	0.03	19.14
6/ 3	7.	0.	151.	0.03	20.34
6/ 4	7.	0.	148.	0.03	21.33
7/ 1	7.	0.	145.	0.03	22.22
7/ 2	6.	0.	143.	0.03	23.06
7/ 3	6.	0.	140.	0.03	23.82
7/ 4	6.	0.	138.	0.03	24.53
8/ 1	5.	0.	136.	0.03	25.22
8/ 2	5.	0.	134.	0.03	25.91
8/ 3	5.	0.	132.	0.03	26.59
8/ 4	5.	0.	130.	0.03	27.29
9/ 1	5.	0.	129.	0.03	27.99
9/ 2	4.	0.	127.	0.03	28.72
9/ 3	4.	0.	125.	0.03	29.45
9/ 4	4.	0.	123.	0.03	30.18
10/ 1	4.	0.	122.	0.03	30.96
10/ 2	4.	0.	120.	0.03	31.74
10/ 3	4.	0.	119.	0.03	32.52
10/ 4	4.	0.	118.	0.03	33.32
11/ 1	3.	0.	117.	0.03	34.12
11/ 2	3.	0.	115.	0.03	35.02
11/ 3	3.	0.	114.	0.03	35.95
11/ 4	3.	0.	113.	0.03	36.83

As shown on the "Gross Revenues Worksheet", gross revenue in each year was calculated by multiplying predicted production by the oil price. A Year 0 oil price was specified, and Eq. 7.5 applied to estimate oil prices in future years, based on assumed inflation and oil price escalation.

Annual operating costs were calculated as the sum of air compressor electricity cost, maintenance costs, labor costs, and engineering costs. Maintenance and labor costs were specified in Year 0 and found for subsequent years by applying Eq. 7.5. Engineering costs were entered for each year.

Electricity costs were calculated by multiplying the annual electricity requirement in kilowatt-hours by the cost of electricity. The Year 0 electricity price was specified and Eq. 7.5 applied for later years. The electricity requirement was found as follows:

$$(\text{Avg. Inj. Rate, MCFD}/1000)(365)(24)(\text{BHP/MMSCF})(0.746\ \text{KW/BHP}) \quad \text{.......... } 10.1$$

where the BHP/MMSCF is taken from White and Moss (1983).

EOR PROJECT DISCOUNTED CASH FLOW ANALYSIS WORKSHEET

EOR PROCESS AND CASE INFORMATION: IN-SITU COMBUSTION

EXPECTED AVERAGE ANNUAL T-BILL RATE:					10.00%
EXPECTED AVERAGE ANNUAL INFLATION RATE:					4.00%
EXPECTED TRUE DISCOUNT RATE:					5.77%
PROJECT LIFE IN YEARS:					9
CASH FLOW COMPONENTS:					
	Year 0	Year 1	Year 2	Year 3	Year 4
Capital Costs	($351445.00)	$0.00	$0.00	$0.00	$0.00
Revenues	$0.00	$258796.00	$1068331.00	$1117370.00	$1107800.00
Op. Costs	$0.00	($102204.11)	($105892.28)	($109727.97)	($113717.09)
Net Cash Flow	($351445.00)	$156591.89	$962438.72	$1007642.03	$994082.91
FV @ TRUE DR		$245269.77	$1425241.66	$1410789.93	$1315889.25
DCF @ True DR	($351445.00)	$148050.51	$860308.86	$851585.46	$794301.21
FV @ 50%		3794372.676	14699183.44	9700090.619	$6031724.83
	Year 5	Year 6	Year 7	Year 8	Year 9
Capital Costs	$0.00	$0.00	$0.00	$0.00	$0.00
Revenues	$1122300.00	$1122300.00	$1122300.00	$278400.00	$0.00
Op. Costs	($117865.77)	($122180.40)	($126667.62)	($131334.32)	($136187.70)
Net Cash Flow	$1004434.23	$1000119.60	$995632.38	$147065.68	($136187.70)
FV @ TRUE DR	$1257068.34	$1183395.67	$1113826.91	$155550.24	($136187.70)
DCF @ True DR	$758795.55	$714325.02	$672331.71	$93893.72	($82206.05)
FV @ 50%	$3841402.47	$2410846.95	$1512746.34	$140840.58	($82206.05)
	Year 10				
Capital Costs	$0.00				
Revenues	$0.00		NFV @ 50%:	42049001.85	
Op. Costs	($141235.20)		GROR @ 50%:	70.17%	
			(FV, NFV & GROR @ 50% ARE		
Net Cash Flow	($141235.20)		USED FOR DCFROR STRAIGHT-		
FV @ TRUE DR	($133531.46)		LINE APPROXIMATION, ref: van Rensburg)		
DCF @ True DR	($80602.68)				
NET PRESENT VALUE =			$4448253.32	***	
NFV @ TRUE DR =			$8107031.75		
NFV @ 0% =			$6268007.44		
GROWTH ROR @ TRUE DR=			41.72%	***	
GROWTH ROR @ 0% DR=			37.73%		
DCF ROR =			107.42%		
PRESENT VALUE RATIO =			12.66	***	

EOR PROJECT CAPITAL COSTS ESTIMATION WORKSHEET: IN-SITU COMBUSTION	
CASE:	
Specify No. of New Injection Wells per Unit Area:	1
Specify No. of New Production Wells per Unit Area:	0
INJECTION WELL DRILLING COST:	$50445.00
PRODUCTION WELL DRILLING COST:	$67795.00
INJECTION WELL COSTS =	$50445.00
PRODUCTION WELL COSTS =	$0.00
Specify Cost of Buildings per Unit Area:	$15000.00
Specify Cost of Air Compressors per Unit Area:	$120000.00
Specify Addl Well Workovers/Stimulation of Existing Wells:	$40000.00
Specify Cost of Gas Monitoring Eqpt per Unit Area:	$4000.00
Specify Cost of Steam Pre-Heat/Linseed Oil Soak:	$100000.00
Specify Other Costs (list):	
(1) Quench Water System	$10000.00
(2) Ignition Eqpt	$2000.00
(3) Safety Eqpt/Perimeter, etc.:	$10000.00
TOTAL CAPITAL COST =	($351445.00)

Drilling & Completion Costs for: IN-SITU COMBUSTION		
RIG TIMES AND RATES:	INJECTOR	PRODUCER
Days Drilling Rig Time Expected =	2	2
Daily Drilling Rig Time Rate =	$1750.00	$1750.00
Daily Fuel Cost =	$1250.00	$1250.00
Completion Rig Time Expected =	3	3
Daily Completion Rig Time Rate =	$1000.00	$1000.00
DRILLING COSTS:		
Rig Move	$3800.00	$3800.00
Rig Time	$3500.00	$3500.00
Bit	$1500.00	$1500.00
Mud, Air Drilling Chemicals	$1500.00	$1500.00
Fuel	$2500.00	$2500.00
Cementing	$6300.00	$6300.00
Stabilizer	$750.00	$750.00
Logging	$4520.00	$4520.00
Casing Crew	$500.00	$500.00
Conductor	$510.00	$510.00
Casing	$5460.00	$5460.00
Air Drilling	$3000.00	$3000.00
Rat Hole	$1400.00	$1400.00
Anchors	$600.00	$600.00
Survey & Stake	$225.00	$225.00
Drilling Costs Subtotal	$36065.00	$36065.00
COMPLETION COSTS:		
Cased Hole Logging	$400.00	$400.00
Perforating	$1630.00	$1630.00
Rods	$0.00	$350.00
Tubing	$1150.00	$1150.00
Wellhead	$5000.00	$500.00
Pumping Unit w/Pump	$0.00	$5000.00
Stimulation, Frac	$0.00	$9500.00
Rig Time	$3000.00	$3000.00
Flowlines	$3200.00	$3200.00
Electrification Including Motor	$0.00	$5000.00
Test Facilities (1/9 per well)	$0.00	$2000.00
Completion Costs Subtotal	$14380.00	$31730.00
Total Cost for Drilling and Completion	$50445.00	$67795.00

Gross Revenues Worksheet: EOR Process Predictions

Specify Present Oil Price (Year 0):					$29.00
Specify Expected Inflation Rate (fraction):					4.00%
Specify Expected Escalation in Oil Prices (+ or −)(fraction):					−4.00%
Specify EOR Process:		In-Situ Combustion			
Specify Case:		10-Acre Base			
Specify Production in each Year:					
Year:	Year 1	Year 2	Year 3	Year 4	
Oil Price:	$29.00	$29.00	$29.00	$29.00	
Production:	8924	36839	38530	38200	
Revenue	$258796.00	$1068331.00	$1117370.00	$1107800.00	
Year:	Year5	Year 6	Year 7	Year 8	
Oil Price:	$29.00	$29.00	$29.00	$29.00	
Production:	38700	38700	38700	9600	
Revenue	$1122300.00	$1122300.00	$1122300.00	$278400.00	
Year:	Year9	Year 10	Year 11	Year 12	
Oil Price:	$29.00	$29.00	$29.00	$29.00	
Production:	0	0	0	0	
Revenue	$0.00	$0.00	$0.00	$0.00	

EOR PROJECT OPERATING COSTS WORKSHEET: IN-SITU COMBUSTION				
CASE:				
Specify Project Life, Years:				10
Specify Expected Annual Inflation:				4.00%
Specify Expected Annual Escalation (+ or -) in Labor Costs:				0.00%
Specify Expected Annual Escalation (+ or -) in Fuel/Elec Costs:				0.00%
Specify Year 0 Electricity Cost, $/KWH:				$0.04
Specify Year 0 Labor/Compressor Operator Cost, $/YR:				$30000.00
Specify BHP/MMSCF (ref: White & Moss):				264
Specify Year 0 Maintenance Cost, $/YR:				$10000.00
COST COMPONENTS:	Year 1	Year 2	Year 3	Year 4
Avg Inj Rate, MCFD	850	850	850	850
ELECTRICITY REQMT, KWH:	1466445.024	1466445.024	1466445.024	1466445.024
CALCULATED FUEL COST	$0.04	$0.04	$0.04	$0.05
Yearly Air Comp. Cost =	$61004.11	$63444.28	$65982.05	$68621.33
Maintenance Costs, $/YR	$10400.00	$10816.00	$11248.64	$11698.59
Comp. Operator, $/YR	$31200.00	$32448.00	$33745.92	$35095.76
Specify Engr Costs, $/YR	$10000.00	$10000.00	$10000.00	$10000.00
Other Operating Costs:				
TOTAL OP COSTS:	($102204.11)	($105892.28)	($109727.97)	($113717.09)

Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
850	850	850	850	850	850
1466445.024	1466445.024	1466445.024	1466445.024	1466445.024	1466445.024
$0.05	$0.05	$0.05	$0.05	$0.06	$0.06
$71366.18	$74220.83	$77189.66	$80277.25	$83488.34	$86827.87
$12166.53	$12653.19	$13159.32	$13685.69	$14233.12	$14802.44
$36499.59	$37959.57	$39477.95	$41057.07	$42699.35	$44407.33
$10000.00	$10000.00	$10000.00	$10000.00	$10000.00	$10000.00
($117865.77)	($122180.40)	($126667.62)	($131334.32)	($136187.70)	($141235.20)

10.2.2 Polymer Flooding Spreadsheet Model

The following pages contain five spreadsheets which were used in the evaluation of economics for polymer flooding in the Shannon formation at NPR-3.

Capital costs were taken as the sum of thue costs listed on the "EOR Project Capital Costs Estimation Worksheet". Costs for new wells were found as explained in Section 10.2.1, and equipment and building costs were also "shared" as explained earlier. For this process, it was assumed that one $100,000 polymer mixing plant would serve 10 injection wells, for a per pattern cost of $10,000. It was also assumed that buildings costs would amount to $10,000 per pattern.

Gross revenues were calculated just as in Section 10.2.1. Operating costs were taken as the sum of maintenance, labor, engineering, and injected polymer costs. These costs were found in the same manner as was used in Section 10.2.1, with the exception of polymer costs. Polymer costs were calculated by multiplying predicted injection, in lb/yr, by the cost of polymer, in $/lb. A specified Year 0 polymer cost was adjusted for later years by Eq. 7.5.

EOR PROJECT DISCOUNTED CASH FLOW ANALYSIS WORKSHEET					
EOR PROCESS AND CASE INFORMATION: POLYMER FLOOD					
EXPECTED AVERAGE ANNUAL T-BILL RATE:					10.00%
EXPECTED AVERAGE ANNUAL INFLATION RATE:					4.00%
EXPECTED TRUE DISCOUNT RATE:					5.77%
PROJECT LIFE IN YEARS:					10
CASH FLOW COMPONENTS:					
	Year 0	Year 1	Year 2	Year 3	Year 4
Capital Costs	($124045.00)	$0.00	$0.00	$0.00	$0.00
Revenues	$0.00	$52925.00	$2180800.00	$2488200.00	$1238300.00
Op. Costs	$0.00	($33499.84)	($74612.62)	($76652.69)	($72744.19)
Net Cash Flow	($124045.00)	$19425.16	$2106187.38	$2411547.31	$1165555.81
FV @ TRUE DR		$32180.94	$3298919.92	$3571175.61	$1631883.48
DCF @ True DR	($124045.00)	$18365.61	$1882687.83	$2038063.68	$931313.05
FV @ 50%		706035.5846	48251229.79	34822228.58	############
	Year 5	Year 6	Year 7	Year 8	Year 9
Capital Costs	$0.00	$0.00	$0.00	$0.00	$0.00
Revenues	$249400.00	$118900.00	$81200.00	$66700.00	$52200.00
Op. Costs	($69107.43)	($66352.25)	($64887.51)	($63998.26)	($63710.09)
Net Cash Flow	$180292.57	$52547.75	$16312.49	$2701.74	($11510.09)
FV @ TRUE DR	$238657.21	$65764.50	$19301.82	$3022.47	($12174.14)
DCF @ True DR	$136201.25	$37531.69	$11015.51	$1724.92	($6947.76)
FV @ 50%	$1034278.25	$190004.16	$37177.36	$3881.07	($10421.64)
	Year 10				
Capital Costs	$0.00				
Revenues	$46400.00		NFV @ 50%:	95649191.42	
Op. Costs	($63744.71)		GROR @ 50%:	94.41%	
			(FV, NFV & GROR @ 50% ARE		
Net Cash Flow	($17344.71)		USED FOR DCFROR STRAIGHT-		
FV @ TRUE DR	($17344.71)		LINE APPROXIMATION, ref: van Rensburg)		
DCF @ True DR	($9898.60)				
NET PRESENT VALUE =			$4925910.77	***	
NFV @ TRUE DR =			8870623.91		
NFV @ 0% =			$5943060.11		
GROWTH ROR @ TRUE DR=			53.26%	***	
GROWTH ROR @ 0% DR=			47.25%		
DCF ROR =			831.91%		
PRESENT VALUE RATIO =			39.71	***	

EOR PROJECT CAPITAL COSTS ESTIMATION WORKSHEET: POLYMER FLOOD	
CASE:	
Specify No. of New Injection Wells per Unit Area:	1
Specify No. of New Production Wells per Unit Area:	0
INJECTION WELL COSTS =	$53045.00
PRODUCTION WELL COSTS =	$0.00
Specify Cost of Workovers to Existing Wells:	$40000.00
Specify Cost of Buildings per Unit Area:	$10000.00
Specify Cost of Mixing Eqpt. per Unit Area:	$10000.00
Specify Other Capital Costs (list):	
(1) Pumps, Fittings, Valves, Gauges	$10000.00
(2) Water Treatment Facilities	$1000.00
(3)	$0.00
TOTAL CAPITAL COST =	($124045.00)

Drilling & Completion Costs for: POLYMER FLOOD		
RIG TIMES AND RATES:	INJECTOR	PRODUCER
Days Drilling Rig Time Expected =	2	2
Daily Drilling Rig Time Rate =	$1750.00	$1750.00
Daily Fuel Cost =	$1250.00	$1250.00
Completion Rig Time Expected =	3	3
Daily Completion Rig Time Rate =	$1000.00	$1000.00
DRILLING COSTS:		
Rig Move	$3800.00	$3800.00
Rig Time	$3500.00	$3500.00
Bit	$1500.00	$1500.00
Mud, Air Drilling Chemicals	$1500.00	$1500.00
Fuel	$2500.00	$2500.00
Cementing	$6300.00	$6300.00
Stabilizer	$750.00	$750.00
Logging	$4520.00	$4520.00
Casing Crew	$500.00	$500.00
Conductor	$510.00	$510.00
Casing	$5460.00	$5460.00
Air Drilling	$3000.00	$3000.00
Rat Hole	$1400.00	$1400.00
Anchors	$600.00	$600.00
Survey & Stake	$225.00	$225.00
Drilling Costs Subtotal	$36065.00	$36065.00
COMPLETION COSTS:		
Cased Hole Logging	$400.00	$400.00
Perforating	$1630.00	$1630.00
Rods	$0.00	$350.00
Tubing	$1150.00	$1150.00
Wellhead	$500.00	$500.00
Pumping Unit w/Pump	$0.00	$5000.00
Stimulation, Frac	$9500.00	$9500.00
Rig Time	$3000.00	$3000.00
Flowlines	$800.00	$3200.00
Electrification Including Motor	$0.00	$5000.00
Test Facilities (1/9 per well)	$0.00	$2000.00
Completion Costs Subtotal	$16980.00	$31730.00
Total Cost for Drilling and Completion	$53045.00	$67795.00

Gross Revenues Worksheet - EOR PROCESS EVALUATION					
Specify Present Oil Price (Year 0):					$29.00
Specify Expected Inflation Rate (fraction):					4.00%
Specify Expected Escalation in Oil Prices (+ or -)(fraction):					-4.00%
Specify EOR Process:		Polymer Flood			
Specify Case:		10-Acre Base			
Specify Production in each Year:					
Year:	Year 1	Year 2	Year 3	Year 4	
Oil Price:	$29.00	$29.00	$29.00	$29.00	
Production:	1825	75200	85800	42700	
Revenue	$52925.00	$2180800.00	$2488200.00	$1238300.00	
Year:	Year5	Year 6	Year 7	Year 8	
Oil Price:	$29.00	$29.00	$29.00	$29.00	
Production:	8600	4100	2800	2300	
Revenue	$249400.00	$118900.00	$81200.00	$66700.00	
Year:	Year9	Year 10	Year 11	Year 12	
Oil Price:	$29.00	$29.00	$29.00	$29.00	
Production:	1800	1600	1300		
Revenue	$52200.00	$46400.00	$37700.00	$0.00	

EOR PROJECT OPERATING COSTS WORKSHEET: POLYMER FLOOD				
CASE:				
Specify Project Life, Years:				10
Specify Expected Annual Inflation:				4.00%
Specify Expected Annual Escalation (+ or -) in Labor Costs:				0.00%
Specify Expected Annual Escalation (+ or -) in Polymer Costs:				0.00%
Specify Year 0 Polymer Cost, $/lb:				$2.00
Specify Year 0 Mixing Plant Operator Cost, $/YR:				$3000.00
Specify Year 0 Maintenance Costs, $/YR:				$10000.00
COST COMPONENTS:	Year 1	Year 2	Year 3	Year 4
Polymer Injected, lb/YR	4798	23369	23127	20317
CALCD POLYMER COST	$2.08	$2.16	$2.25	$2.34
Yearly Polymer Inj Cost =	$9979.84	$50551.82	$52029.46	$47536.03
Yearly Maint Costs, $/YR	$10400.00	$10816.00	$11248.64	$11698.59
Mix Plant Operator, $/YR	$3120.00	$3244.80	$3374.59	$3509.58
Specify Engr Costs, $/YR	$10000.00	$10000.00	$10000.00	$10000.00
Other Operating Costs:				
TOTAL OP COSTS:	($33499.84)	($74612.62)	($76652.69)	($72744.19)

Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
17791	15768	14355	13228	12368	11654
$2.43	$2.53	$2.63	$2.74	$2.85	$2.96
$43290.94	$39903.10	$37780.40	$36206.86	$35207.04	$34501.53
$12166.53	$12653.19	$13159.32	$13685.69	$14233.12	$14802.44
$3649.96	$3795.96	$3947.80	$4105.71	$4269.94	$4440.73
$10000.00	$10000.00	$10000.00	$10000.00	$10000.00	$10000.00
($69107.43)	($66352.25)	($64887.51)	($63998.26)	($63710.09)	($63744.71)

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13						
14	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
15	500	500	500	500	500	500
16	0.36883	0.36883	0.36883	0.36883	0.36883	0.36883
17	$3.65	$3.80	$3.95	$4.11	$4.27	$4.44
18						
19	($277923.19)	($289040.12)	($300601.73)	($312625.80)	($325130.83)	($338136.06)
20						
21	($60832.65)	($63265.95)	($65796.59)	($68428.45)	($71165.59)	($74012.21)
22	($21899.75)	($22775.74)	($23686.77)	($24634.24)	($25619.61)	($26644.40)
23						
24	($30416.32)	($31632.98)	($32898.29)	($34214.23)	($35582.80)	($37006.11)
25	($10000.00)	($10000.00)	($10000.00)	($10000.00)	($10000.00)	($10000.00)
26						
27						
28	($401071.91)	($416714.79)	($432983.38)	($449902.72)	($467498.83)	($485798.78)
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	1	2	3	4	5
1	EOR PROJECT OPERATING COSTS WORKSHEET: STEAM FLOOD				
2					
3	CASE:				
4	Specify Project Life, Years:				9
5	Specify Expected Annual Inflation:				4.00%
6	Specify Expected Annual Escalation (+ or –) in Labor Costs:				0.00%
7	Specify Expected Annual Escalation (+ or –) in Fuel Costs:				0.00%
8	Specify Year 0 Fuel Cost, $/MSCF:				$3.00
9	Specify Steam Generator Efficiency (80% quality), fraction:				85.00%
10	Specify Year 0 Water Treatment/Pumping Costs:				$50000.00
11	Specify Year 0 Salt, Chemical & Maint Matls Costs:				$18000.00
12	Specify Year 0 Labor Cost, $/YR:				$25000.00
13					
14	COST COMPONENTS:	Year 1	Year 2	Year 3	Year 4
15	Avg Inj Rate, BSPD	500	500	500	500
16	Heat Reqmt,MMBTU/Bbl	0.36883	0.36883	0.36883	0.36883
17	CALCULATED FUEL COST	$3.12	$3.24	$3.37	$3.51
18					
19	Yearly Steam Gen. Cost =	($237569.91)	($247072.71)	($256955.62)	($267233.84)
20					
21	Wtr Trt/Pump Costs, $/YR	($52000.00)	($54080.00)	($56243.20)	($58492.93)
22	Salt,etc Matl Costs, $/YR	($18720.00)	($19468.80)	($20247.55)	($21057.45)
23					
24	Gen. Operator, $/YR	($26000.00)	($27040.00)	($28121.60)	($29246.46)
25	Specify Engr Costs, $/YR	($10000.00)	($10000.00)	($10000.00)	($10000.00)
26	Other Operating Costs:				
27					
28	TOTAL OP COSTS:	($344289.91)	($357661.51)	($371567.97)	($386030.69)
29					
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1	Gross Revenues Worksheet - EOR PROCESS EVALUATION					
2						
3	Specify Present Oil Price (Year 0):					$29.00
4	Specify Expected Inflation Rate (fraction):					4.00%
5	Specify Expected Escalation in Oil Prices (+ or -)(fraction):					-4.00%
6						
7	Specify EOR Process:		Steam Flood			
8	Specify Case:		10-Acre Base			
9						
10	Specify Production in each Year:					
11						
12	Year:	Year 1	Year 2	Year 3	Year 4	
13	Oil Price:	$29.00	$29.00	$29.00	$29.00	
14	Production:	45049	37086	30964	27308	
15						
16	Revenue	$1306421.00	$1075494.00	$897956.00	$791932.00	
17						
18						
19	Year:	Year5	Year 6	Year 7	Year 8	
20	Oil Price:	$29.00	$29.00	$29.00	$29.00	
21	Production:	24737	22773	21138	16515	
22						
23	Revenue	$717373.00	$660417.00	$613002.00	$478935.00	
24						
25						
26	Year:	Year9	Year 10	Year 11	Year 12	
27	Oil Price:	$29.00	$29.00	$29.00	$29.00	
28	Production:	19566	16727			
29						
30						
31	Revenue	$567414.00	$485083.00	$0.00	$0.00	
32						
33						
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	7	8	9	10	11	12	13
1	Drilling & Completion Costs for: STEAMFLOOD						
2							
3	RIG TIMES AND RATES:				INJECTOR		PRODUCER
4	Days Drilling Rig Time Expected =				2		2
5	Daily Drilling Rig Time Rate =				$1750.00		$1750.00
6	Daily Fuel Cost =				$1250.00		$1250.00
7	Completion Rig Time Expected =				3		3
8	Daily Completion Rig Time Rate =				$1000.00		$1000.00
9							
10	DRILLING COSTS:						
11	Rig Move				$3800.00		$3800.00
12	Rig Time				$3500.00		$3500.00
13	Bit				$1500.00		$1500.00
14	Mud, Air Drilling Chemicals				$1500.00		$1500.00
15	Fuel				$2500.00		$2500.00
16	Cementing				$6300.00		$6300.00
17	Stabilizer				$750.00		$750.00
18	Logging				$4520.00		$4520.00
19	Casing Crew				$500.00		$500.00
20	Conductor				$510.00		$510.00
21	Casing				$5460.00		$5460.00
22	Air Drilling				$3000.00		$3000.00
23	Rat Hole				$1400.00		$1400.00
24	Anchors				$600.00		$600.00
25	Survey & Stake				$225.00		$225.00
26							
27	Drilling Costs Subtotal				$36065.00		$36065.00
28							
29	COMPLETION COSTS:						
30	Cased Hole Logging				$400.00		$400.00
31	Perforating				$1630.00		$1630.00
32	Rods				$0.00		$350.00
33	Tubing/Thermal Packer				$5150.00		$1150.00
34	Wellhead, Fittings & Valves				$11500.00		$500.00
35	Pumping Unit w/Pump				$0.00		$5000.00
36	Stimulation, Frac				$0.00		$9500.00
37	Rig Time				$3000.00		$3000.00
38	Flowlines				$1500.00		$3200.00
39	Electrification Including Motor				$0.00		$5000.00
40	Test Facilities (1/9 per well)				$0.00		$2000.00
41							
42	Completion Costs Subtotal				$23180.00		$31730.00
43							
44	Total Cost for Drilling and Completion				$59245.00		$67795.00
45							

	14	15	16	17	18	19
1	EOR PROJECT CAPITAL COSTS ESTIMATION WORKSHEET: STEAM FLOOD					
2						
3	CASE:					
4						
5	Specify No. of New Injection Wells per Unit Area:					1
6	Specify No. of New Production Wells per Unit Area:					0
7						
8	INJECTION WELL COSTS =					$59245.00
9	PRODUCTION WELL COSTS =					$0.00
10						
11	Specify Cost of Buildings per Unit Area:					$15000.00
12	Specify Cost of Steam Generator per Unit Area:					$60000.00
13	Specify Cost of Water Softening/Pumping Eqpt per Unit Area:					$27000.00
14	Specify Well Workovers/Stimulation of Existing Wells:					$40000.00
15	Specify Other Costs (list):					$0.00
16	(1) Misc.:					$0.00
17	(2) Production Lines					$0.00
18	(3) Water Supply & Disposal Lines					$20000.00
19						
20						
21	TOTAL CAPITAL COST =					($221245.00)
22						
23						
24						
25						
26						
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EOR PROJECT DISCOUNTED CASH FLOW ANALYSIS WORKSHEET					
EOR PROCESS AND CASE INFORMATION: STEAM FLOOD					
EXPECTED AVERAGE ANNUAL T-BILL RATE:					10.00%
EXPECTED AVERAGE ANNUAL INFLATION RATE:					4.00%
EXPECTED TRUE DISCOUNT RATE:					5.77%
PROJECT LIFE IN YEARS:					9
CASH FLOW COMPONENTS:					
	Year 0	Year 1	Year 2	Year 3	Year 4
Capital Costs	($221245.00)	$0.00	$0.00	$0.00	$0.00
Revenues	$0.00	$1306421.00	$1075494.00	$897956.00	$791932.00
Op. Costs	$0.00	($344289.91)	($357661.51)	($371567.97)	($386030.69)
Net Cash Flow	($221245.00)	$962131.09	$717832.49	$526388.03	$405901.31
FV @ TRUE DR		$1506985.30	$1063012.90	$736990.83	$537300.43
DCF @ True DR	($221245.00)	$909651.21	$641659.19	$444864.72	$324326.98
FV @ 50%		23313365.6	10963348.86	5067287.238	$2462857.97
	Year 5	Year 6	Year 7	Year 8	Year 9
Capital Costs	$0.00	$0.00	$0.00	$0.00	$0.00
Revenues	$717373.00	$660417.00	$613002.00	$478935.00	$567414.00
Op. Costs	($401071.91)	($416714.79)	($432983.38)	($449902.72)	($467498.83)
Net Cash Flow	$316301.09	$243702.21	$180018.62	$29032.28	$99915.17
FV @ TRUE DR	$395856.76	$288361.65	$201389.17	$30707.22	$99915.17
DCF @ True DR	$238948.30	$174061.77	$121563.17	$18535.59	$60311.11
FV @ 50%	$1209675.79	$587458.47	$273517.12	$27803.38	$60311.11
	Year 10				
Capital Costs	$0.00				
Revenues	$485083.00		NFV @ 50%:	43965625.54	
Op. Costs	($485798.78)		GROR @ 50%:	80.04%	
			(FV, NFV & GROR @ 50% ARE		
Net Cash Flow	($715.78)		USED FOR DCFROR STRAIGHT-		
FV @ TRUE DR	($676.74)		LINE APPROXIMATION, ref: van Rensburg)		
DCF @ True DR	($408.49)				
NET PRESENT VALUE =			$2712677.04	***	
NFV @ TRUE DR =			$4860519.42		
NFV @ 0% =			$3481222.29		
GROWTH ROR @ TRUE DR=			40.96%	***	
GROWTH ROR @ 0% DR=			35.83%		
DCF ROR =			309.37%		
PRESENT VALUE RATIO =			12.26	***	

values were found from steam tables given by Prats (1982), and converted from BTU/lb_m to BTU/bbl by multiplying by the factor of (350 lb_m/bbl) of water. The heating value of gas was taken to be 1.04 MMBTU/MCF in these calculations. Finally, the generator efficiency is expressed as a fraction and was taken to be 0.85 for all calculations.

10.2.3 Steamflood Spreadsheet Model

The following pages contain five spreadsheets which were used in the evaluation of economics for steamflooding in the Shannon formation at NPR-3.

Capital costs were computed in the same manner as was given in Section 10.2.1,and some costs were again assumed to be "shared" among well patterns. These capital costs included one 50 MMBTU/HR steam generator to serve 5.5 injection wells which would cost $340,000, for a per pattern cost of $60,000. Costs for buildings, water line costs, and water softening equipment and pump costs were taken to be $15,000, $20,000, and $27,000, respectively, per pattern. Gross revenues were calculated as in Section 10.2.1 and 10.2.2.

Operating costs were calculated as the sum of costs for steam generation, water treatment and pumping, salt and chemicals, labor, and engineering. Except for steam generation costs, these costs were calculated from a Year 0 cost, adjusted for inflation and escalation by Eq. 7.5. Steam generation costs were taken to be·

(Avg. Inj. Rate, BSPD)(365)(MMBTU/bbl)(Fuel Cost, $/MCF) ·
(Heating Value of Fuel, MMBTU/MCF)/(Generator Efficiency, fraction) 10.2

In Eq. 10.2, MMBTU/bbl is the enthalpy difference between feedwater at 14.7 psia and 65°F, and 80% quality saturated steam at 500 psia. These enthalpy

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VITA

Harlan Hugh Chappelle is the son of Harold and Stella Chappelle, and was born in Pleasanton, CA on September 26, 1956. He graduated from John Jay High School in San Antonio, TX in 1974, and enlisted in the U.S. Navy that same year. As an enlisted man, he rose to the rank of Petty Officer First Class. After earning a Bachelor of Chemical Engineering degree from Auburn University through the Navy Enlisted Scientific Education Program in 1981 Harlan Chappelle was commissioned an Ensign in the U.S. Navy Civil Engineer Corps. He entered The Graduate School at The University of Texas at Austin in September, 1984. He has now attained the rank of Lieutenant, and will continue as an officer in the U.S. Navy.

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This report was typed by Harlan H. Chappelle

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